CANADA

National Energy Board

Reasons for Decision

TransCanada PipeLines Limited
Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc.
ICG Utilities (Ontario) Ltd (Gas Export and Reimport)
Indeck Gas Supply Corporation
ProGas Limited
Shell Canada Limited
Western Gas Marketing Limited
Western Gas Marketing Limited as agent for TransCanada PipeLines Limited
Direct Energy Marketing Limited

GH-1-89

December 1989

Volume I - Gas Exports

National Energy Board

Reasons for Decision

IN THE MATTER OF

TransCanada PipeLines Limited

Application Pursuant to Part III of the *National Energy Board Act* for a Certificate to Construct Facilities

AND IN THE MATTER OF

Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc.
ICG Utilities (Ontario) Ltd (Gas Export and Reimport)
Indeck Gas Supply Corporation
Western Gas Marketing Limited
Western Gas Marketing Limited as agent for TransCanada PipeLines Limited
Direct Energy Marketing Limited

Applications Pursuant to Part VI of the *National Energy Board Act* for Licences to Export Natural Gas

AND IN THE MATTER OF

ProGas Limited
Shell Canada Limited

Applications Pursuant to Part I of the *National Energy Board Act* for a Change, Alteration or Variation of Natural Gas Export Licences

Volume I - GH-1-89

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Recital and Appearances

IN THE MATTER OF the *National Energy Board Act,* R.S.C. 1985, c. N-7 ("the Act"), and the regulations made thereunder;

AND IN THE MATTER OF an application dated 29 December 1988, as amended, by TransCanada PipeLines Limited, pursuant to Parts III and IV of the Act, for a certificate in respect of certain proposed facilities, for an order exempting certain of those proposed facilities from the provisions of certain sections of the Act and for an order in respect of the accounting treatment of certain compressor retirements; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF an application dated 31 January 1989 by Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc., an application dated 12 October 1988 by Direct Energy Marketing Limited, an application dated 14 February 1989, as amended, by Indeck Gas Supply Corporation, an application dated 15 February 1989 by Western Gas Marketing Limited and an application dated 14 February 1989 by Western Gas Marketing Limited as agent for TransCanada PipeLines Limited, each seeking a licence to export natural gas pursuant to Part VI of the Act; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF an application dated 10 February 1989 by ICG Utilities (Ontario) Ltd, pursuant to Part VI of the Act, for a licence to export and reimport natural gas; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF an application dated 15 November 1988 by ProGas Limited, pursuant to Part I of the Act for a change, alteration or variation of gas export Licences No. GL-80 and GL-81; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF an application dated 21 November 1988 by Shell Canada Limited, pursuant to Part I of the Act, for a change alteration or variation of gas export Licence No. GL-100; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF Hearing Order No. GH-1-89, as amended.

HEARD at Calgary April 12, 13, 14, 17, 18, 19, 20, 21,
and at Ottawa April 25, 26, 27, 28, and May 1, 2, 3, 4, 23, 24, 25, 30, 31, and June 1, 2, 14, 15, 16, 19, 20, 21, 22, 23 and July 10, 11, 12, 13, 1989.

BEFORE:

A.B. Gilmour	Chairman
R.B. Horner, Q.C.	Member
K.W. Vollman	Member

APPEARANCES:

TransCanada PipeLines Limited	J.M. Murray J.C. Schatz N.D.D. Patterson
Amoco Canada Petroleum Company, Ltd. and Consolidated Edison Company of New York, Inc.	F.R. Foran, Q.C. L. Pillman D. Stover
Direct Energy Marketing Limited	J.T. Brett
ICG Utilities (Ontario) Ltd	J.H. Smellie D. Wilson
Indeck Gas Supply Corporation	K.F. Miller
ProGas Limited	K.J. MacDonald J. Couch
Shell Canada Limited	E.S. Decter
Western Gas Marketing Limited	M.J. Samuel M. Stauft
Canadian Petroleum Association, The	D.A. Holgate
Independent Petroleum Association of Canada, The	A.S. Hollingworth J.A. Snider
Industrial Gas Users Association, The	B.A. Carroll P.C.P. Thompson, Q.C.
ANR Pipeline Company	T.G. Kane R.J. Harrison
Alberta and Southern Gas Co. Ltd.	C. Page K.F. Miller
Alberta Northeast Gas, Limited	L.E. Smith L.G. Keough
B.C. Gas Inc., Inland Natural Gas and Columbia Natural Gas Limited	D. Masuhara
Bonus Gas Processors Corp.	H.R. Ward
Boundary Gas, Inc.	L.E. Smith
Bow Valley Industries Ltd.	K.F. Miller
Canadian Hunter Exploration Ltd.	J.E. Lowe

CanStates Gas Marketing	S. Carscallen
C-I-L Inc.	M.M. Peterson
Champlain Pipeline Company	A.M. Bigué S. Struthers
Cogen Energy Technology Inc.	R. Daileader
Consumers' Gas Company Ltd., The	J.H. Farrell G. Dann H.T. Soudek
Consumers Power Company	F.X. Beckmeier W.M. Lange
Cyanamid Canada Inc. and Cyanamid Canada Pipeline Inc.	J. Ryan
Foothills Pipe Lines (Yukon) Ltd.	J. Hopwood, Q.C.
FSC Resources Ltd.	S.H. Lockwood
Gaz Métropolitain, inc	L.-C. Lalonde
General Chemical Canada Ltd.	M.M. Peterson
Iroquois Gas Transmission System	F. Lowther B. Webb
KannGaz Producers Ltd.	J.T. Horte
Midland Cogeneration Venture Limited Partnership, The	W. Van dam
Midwestern Gas Transmission Company	N.J. Schultz
Michigan Consolidated Gas Company	A.R. O'Brien
Northeast Energy Associates, a Limited Partnership and North Jersey Energy Associates, a Limited Partnership	S. Klurfeld
Northridge Petroleum Marketing, Inc.	A.S. Hollingworth
NOVA Corporation of Alberta	J. Hopwood, Q.C.
Ocean State Power and Ocean State Power II	L.E. Smith K. Simon L.G. Keough
Pan-Alberta Gas Ltd.	M. Grant

PanCanadian Petroleum Limited	J.B. Ballem, Q.C.
Petro-Canada Inc.	S.R. Miller
Polysar Limited	T.M. Hughes
Power City Partners, L.P.	I.B. MacOdrum, Q.C.
PPG Canada Inc.	W. Fruehauf
St. Clair Pipelines Limited	D.G. Hart, Q.C.
Tennessee Gas Pipeline Company	N.J. Schultz
Texas Eastern Transmission Corporation	J. Weiler
Transcontinental Gas Pipe Line Corporation	J.W. Ebert W.G. Burke-Robertson, Q.C. R.D. Loftin
Union Gas Limited	P. Gilchrist G. Cameron
Vermont Gas Systems, Inc.	A.M. Bigué S. Struthers
Alberta Petroleum Marketing Commission, The	P.A. McCunn-Miller
Minister of Energy for Ontario, The	V. Black
Procureur général du Quebec, Le	J . Robitaille
National Energy Board, The	J.A. Vockeroth D. Bursey

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Abbreviations

ABP	adjusted base price
Accounting Regulations	Gas Pipeline Uniform Accounting Regulations
ACQ	Annual Contract Quantity
Act	National Energy Board Act
ADA	ADA Cogeneration
ADQ	Aggregate Daily Quantity
AFFC	Average fossil fuel cost
Alberta and Southern	Alberta and Southern Gas Co. Ltd.
Alcoa	Aluminum Company of America
Algonquin	Algonquin Gas Transmision Company
Amoco	Amoco Canada Petroleum Company Ltd.
Amoco/Con Ed	Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc.
Amoco Resources	Amoco Canada Resources Ltd.
Ancaster	Town of Ancaster, The
ANE	Alberta Northeast Gas, Limited
ANR	ANR Pipeline Company
AOOC	annual owning and operating costs
APMC	Alberta Petroleum Marketing Commission
Arrowhead	Arrowhead Cogeneration Company Limited Partnership
Bcf	billion cubic feet
Board	National Energy Board
Boise Cascade	Boise Cascade Canada Ltd.
BVI	Bow Valley Industries Ltd.
CanStates	CanStates Gas Marketing
Cdn	Canadian

CETI	Cogen Energy Technology Inc.
CIL	C-I-L Inc.
Champlain	Champlain Pipeline Company
Charlottenburg	Corporation of the Township of Charlottenburg, The
Chesapeake	Chesapeake Resources Ltd.
CNG	CNG Transmission Corporation
Con Ed	Consolidated Edison Company of New York, Inc.
Consolidated	Consolidated Fuels Company
Consumers Gas	Consumers' Gas Company Ltd., The
Contract Year	the 12-month period commencing 1 November
CPA	Canadian Petroleum Association
CPCo	Consumers Power Company
DCQ	Daily Contract Quantity
Direct Energy	Direct Energy Marketing Limited
Domtar	Domtar Inc.
Dupont	E.I. Dupont de Nemours and Company
EIA	Export Impact Assessment
EIL	Environmental Issues List
EJ	exajoule(s)
EME	Energy Marketing Exchange, Inc.
Empire State	Empire State Pipeline Company
ERCB	(Alberta) Energy Resources Conservation Board
Falcon Seaboard	Falcon Seaboard Gas Company
FERC	(United States) Federal Energy Regulatory Commission
Fort Orange Paper	Fort Orange Paper Company
Foster	Foster Associates, Inc.
FS	Firm Service

FSC	FSC Resources Limited
FST	Firm Service Tendered
FTA	Free Trade Agreement between the Government of Canada and the Government of the United States of America
GH-2-87	Hearing Order GH-2-87 in respect of TransCanada's application for 1988 and 1989 facilities
GH-4-88	Hearing Order GH-4-88 in respect of TransCanada's application for 1989/90 facilities
GH-8-88	Hearing Order GH-8-88 in respect of export applications of Canterra Energy Ltd., Norcen Energy Resources Limited, Poco Petroleums Ltd., Shell, Vector and WGML/TransCanada
GH-1-89	Hearing Order GH-1-89 in respect of TransCanada's application for 1990 facilities
GHW-3-89	Hearing Order GHW-3-89 in respect of information on gas supply to be provided by TransCanada in support of its 1991 and 1992 facilities application.
General Chemical	General Chemical Canada Ltd.
GIC	gas inventory charge
GJ	gigajoule(s)
GMi	Gaz Métropolitain, inc.
GNP	gross national product
Great Lakes	Great Lakes Gas Transmission Company
Gulf	Gulf Canada Resources Limited
HDGI	Hydro Development Group Inc.
Hydro Engineering	Hydro Engineering, Inc.
ICG Ontario	ICG Utilities (Ontario) Ltd
ICG Resources	ICG Resources Ltd.
ICG Transmission	ICG Transmission Holdings Ltd.
Indeck	Indeck Gas Supply Corporation
Indeck Oswego	Indeck Energy Services of Oswego, Inc.

Indeck-Yerkes	Indeck-Yerkes Energy Services, Inc.
Inverness	Inverness Petroleum Ltd.
IPAC	Independent Petroleum Association of Canada, The
Kamine Milford	Kamine Milford Limited Partnership
KannGaz	KannGaz Producers Ltd.
km	kilometres
kPa	kilopascals
Kraft	Kraft Inc.
Kwh	kilowatt-hour(s)
LDC	local distribution company
LIFS	Limited Interruptible Firm Service
m	metre(s)
m^3	cubic metre(s)
m^3/d	cubic metre(s) per day
Mcf	thousand cubic feet
mm	millimetre(s)
MCV	Midland Cogeneration Venture Limited Partnership, The
MDCQ	maximum daily contract quantity
MDQ	maximum daily quantity
Megan-Racine	Megan-Racine Associates, Inc.
MichCon	Michigan Consolidated Gas Company
Midwestern	Midwestern Gas Transmission Company
Minnesota Pipelines	Inter-City Minnesota Pipelines Ltd.
MLV	mainline valve
MMBtu	million British thermal units
MMcf	million cubic feet
MMcfd	million cubic feet per day

MW	megawatts
National Distribution	National Fuel Gas Distribution Corporation
National Fuel	National Fuel Gas Supply Corporation
NEB	National Energy Board
NEPOOL	New England Electric Power Pool
Niagara Gas	Niagara Gas Transmission Limited
Niagara Mohawk	Niagara Mohawk Power Corporation
Niagara Spur	Niagara Spur Loop Line
NIPPS	Niagara Import Point Projects Settlement
North-Canadian Marketing	North-Canadian Marketing Inc.
Northeast Energy	Northeast Energy Associates, A Limited Partnership
Northern Natural	Northern Natural Gas Company
North Jersey Energy	North Jersey Energy Associates, A Limited Partnership
Northridge	Northridge Petroleum Marketing, Inc.
Northstar	Northstar Energy Corporation
NOVA	NOVA Corporation of Alberta
NSP Wisconsin	Northern States Power Company, A Wisconsin Corporation
NYSPSC	New York State Public Service Commission
O.D.	outside diameter
OEB	Ontario Energy Board
Ontario	Minister of Energy for Ontario, The
Ontario Hydro	Ontario Hydro Corporation
OSP II	Ocean State Power II
Pan-Alberta	Pan-Alberta Gas Ltd.
PanCanadian	PanCanadian Petroleum Limited
Part VI Regulations	*National Energy Board Part VI Regulations*

Penneast	Penneast Gas Services
PGA	Purchase Gas Adjustment
PJ	petajoule(s)
Power City	Power City Partners, L.P.
PPBR	plan, profile and book of reference
PPG	PPG Canada Inc.
ProGas	ProGas Limited
PURPA Regulations	Regulations issued under the authority of the *Public Utility Regulatory Policies Act of 1978*
QF	qualifying cogeneration facility
RH-1-88	Hearing Order RH-1-88 in respect of the 1988/89 toll application of TransCanada PipeLines Limited
R/P ratio	reserves to production ratio
Salmon	Salmon Resources Ltd.
Saskatchewan	Province of Saskatchewan, Department of Environment and Public Safety
Shell	Shell Canada Limited
Southeastern	Southeastern Michigan Gas Company
Sproule	Sproule Associates Limited
St. Lawrence Gas	St. Lawrence Gas Company, Inc.
STS	Storage Transportation Service
Supply/Demand Report	*National Energy Board Canadian Energy Supply and Demand 1987-2005*
1986 Supply/Demand Report	*National Energy Board Canadian Energy Supply and Demand 1985-2005*
TCPL	TransCanada PipeLines Limited
Tennessee	Tennessee Gas Pipeline Company
Tetco	Texas Eastern Transmission Corporation
TIPC	total incremental production costs

TQM	Trans Québec & Maritimes Pipeline Inc.
TransCanada	TransCanada PipeLines Limited
Transco	TransContinental Gas Pipe Line Corporation
TransGas	TransGas Limited
Union	Union Gas Limited
Unitil	Unitil Power Corporation
Universal	Universal Explorations Ltd.
U.S.	United States of America
Vector	Vector Energy Inc.
Vermont Gas	Vermont Gas Systems, Inc.
WAFT	weighted average floating tariff
WCSB	Western Canadian Sedimentary Basin
WGML	Western Gas Marketing Limited
WGML/TransCanada	Western Gas Marketing Limited as agent for TransCanada PipeLines Limited
Winnipeg	City of Winnipeg, The

Chapter 1

Export Applications

1.1 The Applications

The GH-1-89 proceeding was a combined hearing that examined the 1990/91 facilities application of TransCanada PipeLines Limited ("TransCanada"), various applications for the exportation of natural gas, and one application for the exportation and reimportation of natural gas.

During the hearing, the Board examined seven applications for export authorizations associated with TransCanada's 1990/91 system requirements. The applications were filed by the following companies:

1. Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc. ("Amoco/Con Ed");

2. ICG Utilities (Ontario) Ltd ("ICG Ontario");[1]

3. Indeck Gas Supply Corporation ("Indeck");

4. ProGas Limited ("ProGas");

5. Shell Canada Limited ("Shell");

6. Western Gas Marketing Limited ("WGML"); and

7. Western Gas Marketing Limited as agent for TransCanada PipeLines Limited ("WGML/ TransCanada").

The Board also included the export application of Direct Energy Marketing Limited ("Direct Energy") in the proceeding. Direct Energy's requirements were for 1989/90, the associated facilities on the TransCanada system having been approved by the Board in its GH-4-88 decision. The Board included Direct Energy's application in the GH-1-89 proceeding because the application had not been completed until March 1989 and therefore could not be heard, as was originally intended, in the GH-8-88 hearing of January 1989.

Table 1-1 summarizes each of the export applications reviewed during the GH-1-89 proceeding.

1.2 Market-Based Procedure

The Board, in considering an export application, must take into account the requirements of section 118 of the *National Energy Board Act* ("the Act") which requires that the Board have regard to all considerations that appear to it to be relevant. In particular, the Board must satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. The discussion of the Board's Market-Based Procedure that follows is general in nature and applies to each of the export applications heard in the GH-1-89 proceeding.

The Market-Based Procedure includes consideration of the following:

- complaints, if any, under the complaints procedure;
- an export impact assessment ("EIA"); and
- any other factors that the Board considers relevant to its determination of the public interest.

1 Export for reimport for domestic sale.

Table 1-1

Summary of Export Applications
GH-1-89

Applicant (Type of Application)	Buyer (Type of Market)	Term	Daily 10^3m^3 (MMcf)	Term 10^6m^3 (Bcf)	Export Point
1. Amoco/Con Ed (new licence)	Con Ed (system supply)	1 Nov. 1989 31 Oct. 2004	873.0 (30.8)	4 778.0 (168.7)	Niagara Falls Ontario
2. Indeck (new licence)	Indeck Oswego Indeck-Yerkes (2 cogeneration plants)	1 Nov. 1990 31 Oct. 2005	810.0 (28.6)	3 500.0 (123.5)	Niagara Falls Ontario
3. ProGas[1] (amend GL-80 and GL-81)	Tetco (system supply) Northeast Energy (cogeneration plant) North Jersey Energy (cogeneration plant)	1 Nov. 1990 31 Oct. 2005	N/A	N/A	Niagara Falls Ontario
4. Shell (amend GL-100)	Salmon for resale to CETI (cogeneration plant)	Extend from 31 Oct. 2004 to 31 Oct. 2011	450.0 (15.9)	2 755.0 (97.2)	Niagara Falls Ontario
5. WGML (new licence)	Megan-Racine (cogeneration plant)	1 Nov. 1990 31 Oct. 2010	331.0 (11.7)	1 820.0 (64.2)	Cornwall Ontario
6. WGML/TransCanada (new licence)	Niagara Mohawk (system supply)	1 Nov. 1990 31 Oct. 2005	1 445.0 (51.0)	7 910.0 (279.2)	Gananoque Ontario
7. Direct Energy (new licence)	Consolidated Fuel (cogeneration plant)	1 Apr. 1990 31 Oct. 2005	171.0 (6.0)	936.2 (33.0)	Philipsburg Quebec
Total			4 080.0 (144.0)	21 699.2 (765.8)	
8. ICG Ontario[2] (new licence)	ICG Ontario (cogeneration plant)	1 Nov. 1990 31 Oct. 2005	640.0 (22.6)	3 150.0 (111.2)	Sprague Manitoba

1 ProGas' application seeks to amend two existing licences with no increase in term volumes.
2 Export for reimport for domestic sale.

1.2.1 Complaints Procedure

If Canadian gas users have been unable to obtain additional supplies of gas under contract on terms and conditions, including price, similar to those of the proposed export, they may complain to the Board. This provision of the Market-Based Procedure gives Canadian users an opportunity to object to an export application on these grounds.

1.2.2 Export Impact Assessment

The purpose of the EIA is to assist the Board in determining whether a proposed export is likely to cause Canadians difficulty in meeting their future energy requirements at fair market prices. An export applicant is required to assess the ability of Canadian natural gas producers to meet Canadian and export requirements for gas, the impact of the proposed export on domestic natural gas supply, demand and prices, and the ability of Canadian energy markets to adjust to these changes without difficulty.

1.2.3 *Other Factors Relevant to the Public Interest*

The Board's Market-Based Procedure also takes into consideration any other factors that the Board considers relevant in its determination of the public interest. During the GH-1-89 proceeding the Board examined gas supply as it relates to reserves and productive capacity, the markets proposed to be served, upstream and downstream transportation arrangements, sales contracts and net benefits to Canada.

1.2.3.1 Gas Supply

The Board conducted an assessment of gas supply in order to satisfy itself as to the adequacy of reserves and productive capacity to support the applied-for exports.

Each export applicant in the hearing provided estimates of remaining established reserves for those fields from which it intended to produce natural gas for its proposed export. The Board conducted geological and engineering analyses of each applicant's gas supply in order to prepare its own estimate of the applicants' marketable gas reserves.

In its evaluation of gas reserves, the Board made use of its gas reserves database, which is maintained and updated on an ongoing basis. Evaluation of gas reserves included a nomenclature check for correlation purposes, volumetric studies of new pools, re-examination of developing pools and the analysis of producing pools which includes reviewing production and pressure data. A review and evaluation of the ownership and contractual status of all pools included in each of the applications were also conducted.

The applicants submitted estimates of reserves for pools located throughout all producing areas and major producing zones of Alberta and for certain pools in Saskatchewan and British Columbia. The pools varied from small single well pools to very large established pools. Generally, large pools tend to have been producing for a considerable period of time, while single well pools have often not yet been placed in production.

In reviewing marketable gas reserves, the Board evaluated the number, size and distribution (both geographic and geological) of pools for which estimates of reserves had been submitted. In some cases, the Board's pool count was different from that of an applicant because the Board amalgamated or segregated pools on the basis of its interpretation of reservoir data. All references to pool counts in the following chapters are based on the Board's analysis.

The Board's estimates of reserves, along with basic deliverability data for each of the pools for which estimates of reserves were submitted by an applicant, were used in preparing productive capacity projections. Productive capacity projections are generally adjusted to reflect an applicant's expected requirements for gas. The adjusted productive capacity is the estimated productive capacity at any point in time, carrying forward for future use any productive capacity resulting from an earlier excess of productive capacity over production. The requirement estimates shown in the productive capacity figures included in Chapters 2 to 9, with the exception of ProGas, are based on assumed load factors of 100 percent and may therefore somewhat overstate the applicants' actual supply requirements. In the case of ProGas, the Board's estimate of requirements assumed a load factor of 90 percent.

1.2.3.2 Transportation and Sales Contractual Arrangements

The Board conducts its review of these commercial arrangements in order to determine whether the proposed export arrangements are in the Canadian public interest. The Board's review of the commercial arrangements includes:

- the contractual commitments for gas supply in the province of production;
- upstream and downstream transportation arrangements;
- the contractual obligations entered into between the Canadian seller and the United States of America ("U.S.") buyer; and
- any resale arrangements that occur beyond the border sale point, if such arrangements could influence or affect the international sales agreement.

The Board reviews the sales contracts entered into between the Canadian seller and the U.S. buyer to determine whether the contracts:

- recover associated Canadian intraprovincial and interprovincial transportation costs;

- allow for flexibility in order to reflect changing market conditions over time;

- ensure that volumes contracted for will be taken; and

- have the support of the Canadian producers supplying gas to the project.

1.2.3.3 Benefit-cost Analysis

In order to demonstrate that the proposed export would provide net benefits to Canada, each of the export licence applicants in the GH-1-89 hearing submitted a benefit-cost analysis assessing the net benefits to Canada that would result from its project. In conjunction with each benefit-cost analysis, the applicants conducted sensitivity analyses that provided an indication of possible outcomes under a range of assumptions about the critical variables. The results of each applicant's analysis and of the benefit-cost analyses that the Board undertook as part of its assessment of the applicants' submissions, are discussed in Chapters 2 through 9 of these Reasons.

After the applicants submitted their own analyses, the Board issued an information request asking applicants to submit benefit-cost analyses using a number of standard assumptions and procedures. This allowed the Board to evaluate the net benefits to Canada of the export proposals on a basis that is consistent and comparable where appropriate, as explained in Appendix I.

A benefit-cost analysis evaluates a project from a public interest perspective rather than from the perspectives of private firms involved. A benefit-cost analysis is appropriate when the benefits and costs of a project are different for the parties undertaking it than they are for the country as a whole. Two main factors for which private and public values may differ with regard to natural gas exports are transportation costs and total incremental production costs.

The transportation costs relevant for Canadian gas exporters and U.S. importers are the pipeline tolls which they must pay. On the TransCanada pipeline system tolls are calculated on a "rolled-in" basis, i.e. the price the pipeline charges is set to recover its aggregate cost of service once the additional costs of any new facilities required for an export are "rolled-in" to the existing rate base. However, the cost of the new facilities required for an export may be greater than the toll which the pipeline charges for its services. In these circumstances the toll that the exporter faces does not indicate the real cost of the pipeline expansion required to move its gas. The benefit-cost analysis includes, as a cost of making the exports, the estimated costs of the pipeline expansion required to transport the exporter's gas and not the actual tolls which would be charged by the pipeline.

Total incremental production costs ("TIPC") include the direct costs of producing additional gas resulting from increased exports and user costs. User costs occur if increased gas production resulting from the increased export brings forward in time the production of more costly gas reserves. This occurs when, in aggregate, the costs of finding, developing and producing natural gas increases over time as producers must find and develop increasingly smaller and deeper gas reserves or move into more remote areas. In these circumstances, the production of reserves to satisfy an incremental gas export results in an increasing aggregate cost of satisfying all anticipated future gas demand.

The individual producer may not value user costs in the same way that the costs accrue to Canada as a whole. This can happen because the individual producer may not think that its own replacement costs will coincide with those of the industry as a whole. But the industry and the country face the aggregate impact of increasing current production on the incremental costs of providing aggregate future supply. Furthermore, user costs accrue over a long future time period following any increase in current production. Individual producers may not place the same value on these future costs as may the rest of Canada. For their own reasons producers may place a higher value on current income and a lower value on future costs than may society as a whole. In these conditions, private parties may negotiate contracts which adequately recover costs as valued by them, but fail to do so in respect of the increase of aggregate cost attributable to an export, as valued by society at large. Benefit-cost analysis examines the export arrangement in terms of the impact it has on TIPC as seen by the country as a whole. Viewed in this light, the benefit-cost analysis is a method for evaluating export proposals from a national perspective.

1.3 Cogeneration Plants

Five of the eight export licence applicants (see Table 1-2) proposed to export natural gas for use by one or more cogeneration facilities.[1] In addition, ICG Ontario has applied to export and reimport natural gas to supply a cogeneration plant in Ontario.

In all cases, the proposed plants would employ combined cycle technology, utilizing both combustion turbine and steam turbine-driven electrical generating equipment to improve conversion efficiency.

Regulations issued under authority of the (United States) *Public Utility Regulatory Policies Act of 1978* ("the PURPA Regulations") require electric utilities to buy all of the electricity generated by a qualifying cogeneration facility ("QF")[2] and, unless the electric utility and the QF otherwise agree, to pay the QF not more than the full avoided-cost of producing the electricity.

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1 A cogeneration facility is defined as a facility that produces "electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy". 18 C.F.R. s. 292.202(c) (1980)

2 A QF is a cogeneration plant that meets certain ownership criteria and operating and efficiency standards established by the PURPA Regulations. The ownership criteria provide that, with certain exceptions, a QF may not be owned by a person primarily engaged in the generation or sale of electric power. The operating and efficiency standards deal with the numerical relationships between the facility's total energy input, useful power output and useful thermal energy.

Table 1-2

Cogeneration Projects for which Export Licence Applications Were Filed

Applicant	Cogeneration Project Capacity (MW)	Electrical Customer	Steam Customer	Annual Gas Volumes (Bcf/yr)
Indeck	Oswego (50)	Niagara Mohawk	International Paper Company	
	Yerkes (49)	Niagara Mohawk	DuPont	Total 10.3
ProGas	Northeast (300) Energy Company	Boston Edison Company Commonwealth Electric Co. Montaup Electric	Own CO_2 Plant leased to National Energetics Corporation	
	North Jersey Energy (300)	Jersey Central Power and Light Company	Hercules,Inc.	Total 26.3
Shell	CETI (60)	Niagara Mohawk	Fort Orange Paper	5.1
WGML	Megan-Racine (49)	Niagara Mohawk	Kraft	4.3
Direct Energy	Arrowhead (28)	Unitil Power Corporation	Wyeth Nutritionals Inc.	2.2
Total U.S.	836 MW			48.2
		Canadian Cogeneration Project		
ICG Ontario	ICG Ontario (100) (Fort Frances)	Ontario Hydro	Boise Cascade	7.4
Total All Projects:	936 MW			55.6

Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc.

2.1 Application Summary

By joint application dated 31 January 1989, Amoco/Con Ed, pursuant to Part VI of the Act, sought a new natural gas export licence with a term of 15 years commencing 1 November 1989 or as soon thereafter as transportation and regulatory approvals are in place.

The gas proposed for export would be produced in Alberta from reserves owned by Amoco Canada Petroleum Company Ltd. ("Amoco") and Amoco Canada Resources Ltd. ("Amoco Resources")[1]. The gas would be transported by NOVA Corporation of Alberta ("NOVA") and TransCanada to Niagara Falls, Ontario. From the international border, the gas would be transported by Transcontinental Gas Pipe Line Corporation ("Transco") to the distribution system of Consolidated Edison Company of New York, Inc. ("Con Ed"). Con Ed is a natural gas and electric utility serving New York City. It would utilize the proposed export as part of its system supply.

Amoco/Con Ed applied for a licence with the following terms and conditions:

Term	- 1 November 1989 to 31 October 2004 (15 years)
Point of Export	- Niagara Falls, Ontario
Maximum Daily Quantity	- 873.0 10^3m^3 (30.8 MMcf)
Maximum Annual Quantity	- 319.0 10^6m^3(11.3 Bcf)
Maximum Term Quantity	- 4 778.0 10^6m^3(168.7 Bcf)

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an EIA; and other factors which the Board considers relevant in its determination of the public interest including, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements, markets, and net benefits to Canada.

2.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Amoco/Con Ed export proposal.

2.3 Export Impact Assessment

Amoco/Con Ed analyzed three forecasts of supply and demand including exports. In the original EIA submitted with the application, Amoco/Con Ed estimated that the annual applied-for export vol-

1 Amoco Resources was formed by the amalgamation of Dome Petroleum Limited and Hudson's Bay Oil and Gas Company Limited (approved by Order No. MO-5-89 dated 13 April 1989).

umes represented about four-tenths of one percent of total forecasted demand for Canadian gas. This estimate was not significantly altered by revisions to the EIA made to reflect more recent forecasts of Canadian gas supply and demand.

Based on their analysis, Amoco/Con Ed concluded that the ability of Canadian gas producers to satisfy domestic and export requirements would not be reduced as a result of its gas export proposal. Amoco/Con Ed also stated that this conclusion was not altered by assuming prior approval of a number of other applications submitted to the Board. While prior approval of other export applications would raise marginal supply costs, the resulting levels would still be generally lower than estimates of gas prices in forecasts analyzed by Amoco/Con Ed.

Amoco/Con Ed were of the view that Canadian gas prices will be established on the basis of total North American supply and demand. In this context Amoco/Con Ed did not expect the relatively small volumes of their proposed exports to affect future domestic gas prices.

Views of the Board

The Board agrees with Amoco/Con Ed's conclusion that the applied-for export volumes should have little impact on Canadian production, consumption and prices of natural gas and that Canadian energy users would not have any difficulty in meeting their future energy requirements.

2.4 Gas Supply

2.4.1 Supply Contracts

The gas supply for the Amoco/Con Ed export licence would be provided by Amoco and by Amoco Resources, each of which would supply the export from its own pools. No gas supply contracts were therefore required.

2.4.2 Reserves

Table 2-1 shows that the Board's estimate of Amoco/Con Ed's remaining marketable gas reserves is 18 percent higher than that of Amoco/Con Ed and exceeds Amoco/Con Ed's applied-for term volume by 40 percent. The Board's interpretation of pool area, net pay, and ownership generally accounts for its higher estimates of reserves.

Table 2-1

Comparison of Estimates of Amoco/Con Ed's Remaining Marketable Gas Reserves with the Applied-for Term Volume
10^6m^3 (Bcf)

Amoco/Con Ed[1]	NEB[2]	Applied-for Term Volume
5 666 (200)	6 703 (237)	4 778 (169)

1 as of December, 1987
2 as of December, 1988

In its analysis of Amoco/Con Ed's gas supply, the Board recognized a total of 91 gas pools in Alberta. Most of these pools are found within the Cretaceous and Triassic zones in west-central Alberta. Approximately 70 percent of Amoco/Con Ed's reserves are contained in eight large, established pools, each having initial established reserves in excess of 1 000 10^6m^3 (35 Bcf).

In the application, the pools of Amoco and Amoco Resources were divided into the following three groups:

- pools for which Amoco/Con Ed estimated net remaining marketable reserves of 3 261 10^6m^3 (115 Bcf);
- pools for which estimates of reserves of 1 782 10^6m^3 (63 Bcf) were adopted by Amoco/Con Ed from the Alberta Energy Resources Conservation Board ("ERCB"); and
- pools for which estimates of reserves of 623 10^6m^3 (22 Bcf) were adopted from the ERCB.

The Board's estimate of reserves for the first group of pools is 4 558 10^6m^3 (161 Bcf), or 140 percent of the corresponding Amoco/Con Ed estimate. The major differences are in the Wembley/Valhalla Halfway B associated gas and the Pembina Lobstick Glauconitic E and G pools. In Wembley/Valhalla, the difference of 710 10^6m^3 (25 Bcf) is mainly due to an increase in pool area and ownership based on a recent geological study conducted

by the Board. In Pembina, it appears that Amoco/Con Ed used ERCB reserves data. The Board's estimate exceeds that of the ERCB by 768 10^6m^3 (27 Bcf) due to a larger area, higher porosity and higher gas saturation.

For the remaining pools in the first group, Amoco/Con Ed's estimate of reserves is 689 10^6m^3 (24 Bcf), whereas the Board assigned 499 10^6m^3 (18 Bcf). In several pools the area adopted by the Board is less than that used by Amoco/Con Ed, as the Board used 150 or 200 hectares for single well pools while Amoco/Con Ed used a full section. The assignment of a full section for single well pools is not generally accepted by the Board. The methodology used by the Board to determine pool area assignments results from detailed analysis of single well pools and generally conforms to guidelines that the ERCB has recently adopted for single well pools.

The Board's estimate of reserves for the second group of pools is 1 668 10^6m^3 (59 Bcf), or 94 percent of Amoco/Con Ed's estimate. Of the 73 pools, 36 had differing estimates of reserves.

The Board's estimate of reserves for the third group of pools is 477 10^6m^3 (17 Bcf), or 77 percent of Amoco/Con Ed's estimate. The differences are primarily in the Leaman field. The Board assigned reserves based on an interpretation that two pools exist, whereas Amoco/Con Ed evaluated the accumulation as one large pool.

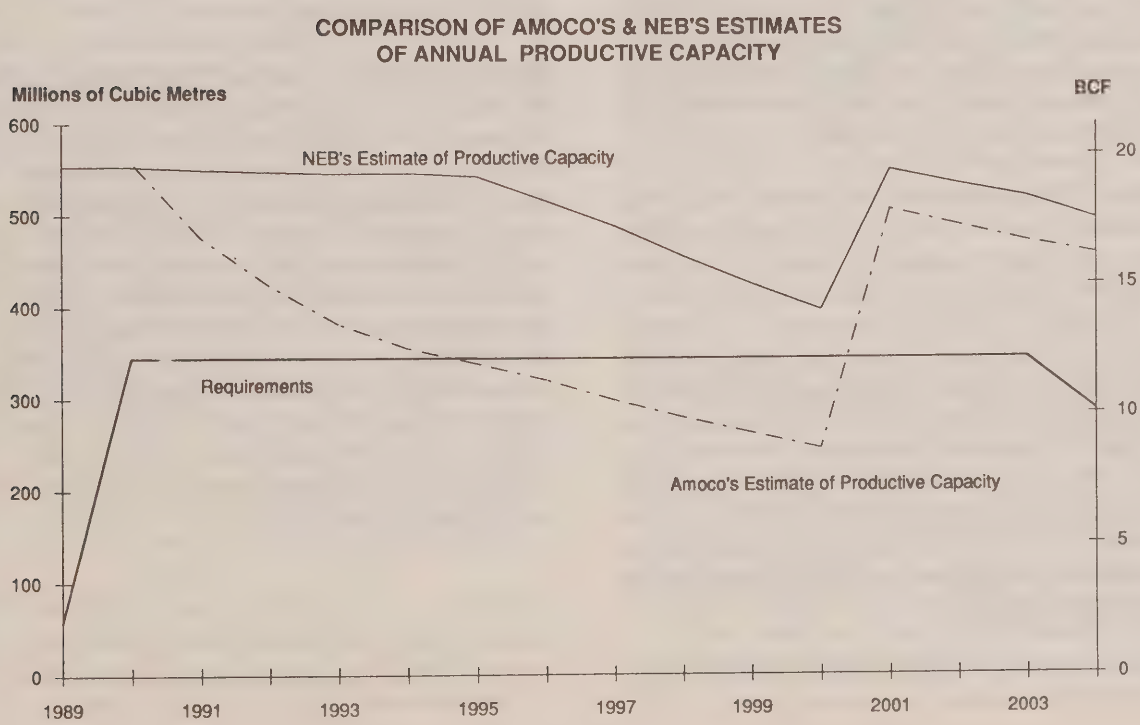
In summary, the Board's total estimate of reserves is higher than that of Amoco/Con Ed primarily because of net pay and area differences in the Wembley/Valhalla and Pembina fields.

2.4.3 Productive Capacity

Figure 2-1 compares the Board's and Amoco/Con Ed's projections of productive capacity with the applied-for volumes, including fuel and shrinkage.

The Board's projection suggests that adequate productive capacity exists throughout the proposed export term. Amoco/Con Ed's projection indicates potential deficiencies in productive capacity from 1995-2000 and a surplus of productive capacity

FIGURE 2-1



thereafter as the Wembley Halfway 'B' blowdown commences. The difference in projections is mainly attributable to a higher estimate by the Board of reserves for the Pembina field.

The Board also notes that Amoco/Con Ed provided evidence with respect to the combined aggregate supply and requirements position of Amoco and Amoco Resources. On a corporate basis, Amoco has a surplus of supply relative to requirements throughout the term of the proposed export licence.

Views Of The Board

The Board is satisfied with Amoco/Con Ed's supply position based on the pool information which has been submitted. The Board has taken account of the fact that Amoco and Amoco Resources have not dedicated specific pools to the export, but rather will rely on their corporate surplus of gas to satisfy the export requirements or to make up any shortfalls in productive capacity.

2.5 Energy Removal Authorizations

An application has been filed with the ERCB for an Alberta removal permit. A decision is pending.

2.6 Market

The Amoco/Con Ed export will be used by Con Ed which serves over one million retail natural gas customers in New York City and the County of Westchester, New York. Con Ed also uses natural gas to generate electricity and steam which it retails to over 2.9 million customers.

Amoco/Con Ed stated that Con Ed has traditionally purchased most of its gas supplies from three interstate pipeline companies; namely, Transco, Texas Eastern Transmission Corporation ("Tetco"), and Tennessee Gas Pipeline Company ("Tennessee"). However, Con Ed has recently embarked on a program to diversify its supply sources and has negotiated alternate purchases from other U.S. pipeline companies. Con Ed is a purchaser from the TransCanada/Boundary Gas Phase II project and also acquires supplies on the spot market. Con Ed's proposed purchase of gas from Amoco[1] is an effort by Con Ed to further diversify its gas supply.

Amoco/Con Ed filed a supply/requirements analysis for Con Ed's market area which showed total requirements increasing from about 203 Bcf per year in 1989/90 to 311 Bcf per year by 2002-2003. The change in requirements over the licence period was attributable to requirements for generating electricity and steam increasing from 98 Bcf per year to 183 Bcf per year and a forecasted increase in the core market (residential and small commercial requirements) from 85 Bcf per year to 107 Bcf per year. The proposed exports would account for less than five percent of Con Ed's total requirements during the licence period.

Amoco/Con Ed submitted that the applied-for export volumes were required by Con Ed as soon as possible in order to serve its firm core market requirements. The core market currently has a low level of saturation and has demonstrated two percent per annum growth regardless of pricing and other fluctuations in the marketplace.

Amoco/Con Ed indicated that the export price during the summer months would be set so that it could compete with alternative fuels which could be used to generate steam and electricity in Con Ed's market. Given this pricing capability, Amoco/Con Ed expected that gas requirements for these purposes would nearly double during the period to 2003.

2.7 Contractual Arrangements

2.7.1 Transportation

Amoco/Con Ed will rely on the Alberta production of Amoco and Amoco Resources for the gas to be exported to Con Ed. The gas will be transported within Alberta by NOVA to TransCanada's facilities at Empress, Alberta. TransCanada will transport the gas to Niagara Falls, Ontario, where it will be delivered to Transco for transportation to Con Ed's delivery area. The facilities necessary to transport the gas in the United States are the subject matter of three separate filings with the Federal Energy Regulatory Commission ("FERC") from National Fuel Gas Supply Corporation ("National Fuel"), Tennessee and Transco. At the time of the GH-1-89 hearing, decisions on these matters were pending.

1 Con Ed would be purchasing from Amoco in its own right and from Amoco as agent for Amoco Resources

Amoco/Con Ed stated that Amoco had entered into a contract with NOVA for the transportation of the proposed exports within Alberta. As well, Amoco and Con Ed have executed transportation precedent agreements with TransCanada and Transco, respectively, providing for transportation of the proposed exports from the Alberta border to Con Ed's facilities in New York.

2.7.2 Sales Contracts

A Gas Purchase Contract dated 1 September 1988 has been executed by Amoco (in its own right and as agent for Amoco Resources)[1] and Con Ed. The contract term is for the first partial contract year to 31 October and for 14 years following. The contract includes a provision for automatic subsequent five-year extensions unless terminated by either party.

The maximum daily contract quantity ("MDCQ") is 30 000 million British thermal units ("MMBtu")[2]. Amoco is also required to provide, at no cost to Con Ed, an incremental volume of approximately 8 000 MMBtu/day for fuel and unaccounted-for losses for transportation by Transco.

Amoco has offsale rights up to the MDCQ provided it has met Con Ed's nomination.

The gas export price will be a two-part rate composed of a monthly demand charge and a commodity charge. The demand charge will recover the sum of the monthly demand tolls payable by Amoco to transport the gas on the NOVA and TransCanada systems. The commodity charge will be set to equal the arithmetic average of the previous monthly sales for Transco's Zone 3 (CD3) rate, Tetco's Zone D (DCQ-D) rate and Tennessee's Zone 5 (CD5) rate less the demand and other transportation charges that are payable by Con Ed for U.S. and Canadian transportation to its system in New York State. The transportation charges deducted do not include fuel that is provided by Amoco nor any separately stated charges designed to recover pipeline take or pay costs incurred prior to 1989. This pricing mechanism ensures that Amoco's gas will be competitively priced with alternate U.S. gas supplies available to Con Ed at New York City.

Notwithstanding the above-noted commodity charge, during the summer period (April through October inclusive), the commodity charge for all gas taken up to 35 percent of the MDCQ will be set to equal the lesser of the above-described commodity charge or Con Ed's residual oil equivalent price.[3] During the summer months (when the residual oil equivalent price is less than the commodity charge, as calculated based on Transco, Tetco and Tennessee rates), the commodity charge applicable to quantities taken above a 65 percent load factor will be the residual oil equivalent price less the above-outlined demand and transportation charges. This provision ensures that a portion of the gas will remain competitive with 0.3 percent sulphur residual oil during the summer period.

The sales agreement provides for a floor price below which the residual oil equivalent price cannot fall. This floor price is calculated on the basis of a 1 November 1987 price of $U.S. 2.64/MMBtu which is indexed to the U.S. gross national product ("GNP") deflator as issued by the U.S. Department of Commerce.

Amoco will pay all taxes and assessments imposed on Con Ed for transportation of the proposed export volumes in the U.S. Con Ed indicated that the charge applicable under this condition would currently be approximately $U.S. 0.017/MMBtu. This rate includes the Gas Research Institute surcharge of approximately $U.S. 0.015/MMBtu plus a charge for partial FERC funding.

Amoco/Con Ed indicated that the net export revenue reported to the Board would include the above-noted charges as well as the fuel and unaccounted-for losses. Amoco/Con Ed calculated that the export price for March 1989 would have been $U.S. 2.85/MMBtu which included a demand charge for Canadian transportation equal to $U.S. 0.75/ thousand cubic feet ("Mcf").

1 Throughout Subsection 2.7.2 of these Reasons, unless a contrary intention is evident, all references to Amoco are to be read as referring to the company in its dual capacity (i.e. in its own right and as agent for Amoco Resources).

2 The contract provides for review of the contract quantities over the life of the contract to ensure that Amoco has available to it adequate productive capacity to meet these contract levels.

3 Amoco's residual oil equivalent price is based on the price paid for residual oil by Con Ed adjusted for New York State business taxes, spill taxes, variable storage and handling costs and oil versus gas efficiency.

The commodity charge is renegotiable commencing 1 November 1995. Con Ed may request renegotiation at that time if the weighted average annual price[1] is more than 130 percent of a similarly weighted market value index price that is made up of the high and low spot gas prices available to Con Ed from each of Tennessee, Tetco and Transco, including firm transportation rates. Amoco may request renegotiation of the commodity charge if the weighted annual average price calculation is less than 110 percent of the spot price calculation.

If the parties fail to reach agreement on a redetermined price, the party that requested renegotiation may terminate the contract on 60 days notice. Upon notice of termination, the other party may elect to compel continuation of the contract by agreeing to accept the alternate price used in the renegotiation provision. If the contract is terminated there is a phase-out period which may vary from one to four years. During this period demand charges must be paid for a minimum of two years. Commodity charges during this phase-out period may vary and would be payable for a minimum one year period.

The Amoco/Con Ed Gas Purchase Contract includes a gas inventory charge ("GIC") which obligates Con Ed to pay Amoco for quantities of gas not taken up to certain threshold quantities. The applicable threshold quantity will be based on the arithmetic average of the percentages required to be taken under GIC provisions pursuant to Con Ed's contractual obligations with each of Transco, Tennessee and Tetco. The GIC rate will be the average of the ratios of the applicable GIC rates to the pipeline's weighted average cost of gas for the same three pipeline companies. Amoco/Con Ed stated that there were no GIC's in effect at the time of the hearing but stated that the threshold quantities would be 60 percent of the MDCQ during the first partial year and next four full years of the contract and 70 percent of the MDCQ thereafter. Also, the rate is to be 20 percent of the net of the commodity charge less Amoco's avoided Canadian transportation charges and fuel.

Views of the Board

The Amoco/Con Ed Gas Purchase Contract includes a monthly demand charge (payable by Con Ed) which is designed to recover the sum of the monthly demand tolls payable by Amoco to transport gas within Canada on the NOVA and TransCanada systems. The Board considers that this demand charge will ensure recovery of the associated Canadian fixed costs of transportation.

The Amoco/Con Ed Gas Purchase Contract includes pricing provisions that establish a commodity price for Canadian gas delivered to Con Ed at New York City equal to the utility's other major U.S. gas suppliers. In addition, the contract includes seasonal pricing adjustments to allow Con Ed to compete with residual fuel oil for at least 35 percent of the daily sales quantity. Finally, the contract contains conditions whereby the pricing provisions of the contract can be renegotiated whenever it is determined that the export price is not market-responsive.

The Board is satisfied that the Amoco/Con Ed contract will be sufficiently flexible to ensure that any necessary adjustments to maintain price competitiveness can be made.

The Gas Purchase Contract includes a GIC for gas not taken up to 60 percent of the MDCQ for the first four years of the contract and 70 percent thereafter. As well, the inclusion of a monthly demand charge, payable regardless of throughput, will also act as an incentive to take gas under the contract.

The Board is of the view that the contract provides adequate assurance of take.

Producer support is evidenced by the fact that the gas proposed for export will be produced from the Alberta gas pools of Amoco and Amoco Resources.

2.8 Benefit-cost Analysis

Amoco/Con Ed submitted a benefit-cost analysis of their joint export licence application which indicated net benefits to Canada of $53 million (1988$), with all project benefits and costs discounted at 8 percent real. The base case scenario assumed world oil prices that are lower than those included in the report entitled *National Energy Board Canadian Energy Supply and Demand 1987-2005* dated September 1988 ("the Supply/Demand Report"). Amoco/Con Ed also submitted

1 The weighted average annual price is the sum of the summer monthly prices times .35 plus the sum of the winter monthly prices, all divided by 7.45.

benefit-cost results incorporating user costs calculated according to the low and high oil price scenarios included in the Supply/Demand Report. Under those scenarios, the net social benefits were $26 million (1988$) in the low case and $103 million (1988$) in the high case. The results of the base case and the low and high oil price scenarios are summarized in Table 2-2.

The contractual pricing terms stipulate that the gas export price is tied to the average delivered prices of U.S. gas in New York City during the winter months. During the summer months, the price for the first 35 percent of the MDCQ is tied to the lesser of either the natural gas prices as determined under the contract or No. 6 fuel oil prices in New York. The remaining 65 percent of the MDCQ is tied to No. 6 fuel oil prices in New York City.

Amoco/Con Ed used a gas price equal to $2.96/MMBtu (1988$) escalated at 2 percent real until the end of the contract term which was based on an average of the system sale prices of Tetco, Tennessee and Transco in the New York City region. Amoco/Con Ed also used a forecast of No. 6 fuel oil prices at New York City which was escalated according to the Western Texas Intermediate price forecast provided in TransCanada's 1989-90 facilities application. To estimate the price at the Niagara Falls export point, Amoco/Con Ed subtracted $U.S. 0.40/MMBtu (1988$) to reflect the transportation charges from Niagara Falls to New York City.

The by-product revenues associated with the applied-for exports were calculated as the total volume of gas delivered to NOVA multiplied by a value set to equal 12 percent of TransCanada's estimate of the world oil price in Chicago. The resulting by-product revenues increased the estimate of total revenues by 16 percent.

An average load factor of 100 percent was assumed by Amoco/Con Ed for the term of the contract.

Amoco/Con Ed's estimate of transportation costs included $42 million (1988$) of capital costs on TransCanada and $8 million (1988$) on NOVA. The NOVA estimate was based on cost estimates contained in the benefit-cost study provided in respect of the Ocean State Power II ("OSP II") export application and the TransCanada estimate was provided by TransCanada.

To estimate the user cost associated with the applied-for export volumes, Amoco/Con Ed used the lesser of currently licensed exports or a forecast of exports prepared by the Independent Petroleum Association of Canada ("IPAC"). This methodology results in a forecast in which exports decline continuously after 1993. Amoco/Con Ed argued that this methodology was appropriate because it defined the amount of gas that Canada will likely supply to the U.S. market given the current level of export authorizations. However, in response to an information request from the Board, Amoco/Con Ed submitted benefit-cost analysis results based upon the Board's projection of exports. Those results showed positive net benefits under both the low and high oil price scenarios.

In summary, Amoco/Con Ed indicated that the proposed sale represents an economically efficient use of the gas from an overall Canadian perspective.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based,among other things,upon Appendix I to which the reader is referred for further details.

The Board used aggregate industry data to calculate by-product revenues and used a projection of exports rather than simply currently licensed exports to calculate the TIPC (including user costs).

The Board adopted Amoco/Con Ed's load factor assumption of 100 percent in its analysis and performed sensitivity tests at 85 and 90 percent load factors.

In estimating the incremental capital costs associated with the transportation of the proposed export volumes, the Board included a credit for the useful economic life of the facilities after the term of the exports.

The Board developed its own projection of the price of gas under the contract using data and assumptions from the Supply/Demand Report. The Board views the North American gas market as a largely integrated, competitive market and therefore expects that delivered gas prices in the northeast United States will be similar for all sources of sup-

ply. The price of Alberta gas delivered to the northeast United States can therefore be approximated by adding the cost of transportation to the Alberta wellhead price.

Amoco/Con Ed assumed a constant exchange rate of $0.83 U.S./Cdn and an inflation rate projection that stays constant at 4.4 percent after 1998. The Board used inflation and exchange rates consistent with the Supply/Demand Report assumptions, so as to be consistent with other data used in its analyses. The Board's projection of inflation rates is generally lower than that of Amoco/Con Ed in the low oil price case, and higher in the high oil price case. The Board's projection of the exchange rate after 1990 is lower than that used by Amoco/Con Ed.

The results of the Board's control case benefit-cost and sensitivity analyses (summarized in Tables 2.3 and 2.4) indicate that in most of the sensitivities examined, the applied-for exports are likely to provide net benefits to Canada.

2.9 Disposition

The Board has decided to issue a gas export licence to Amoco/Con Ed[1]. In order for the licence to take effect, Governor in Council approval thereof is required. Appendix II contains the terms and conditions of the licence including a condition that states that the term of the licence shall commence on the date that Governor in Council approval is received and shall end on 31 October 1991, unless exports commence under the licence on or before 31 October 1991, in which case the term will end on 31 October 2004.

In arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia,* whether the volumes to be exported are surplus to

1 In view of the fact that Amoco will be acting in its own right and as agent for Amoco Resources, the licence will identify Amoco in this dual role.

Table 2-2

Amoco/Con Ed's Benefit-cost Analysis of their Proposed Export
(millions of 1988$, discounted at 8 percent)

	Low User Cost Case	Base Case	High User Cost Case
Export Revenue	288	288	288
By-product Revenue	47	47	47
Less			
Transportation Costs	73	73	73
Total Increase In Production Costs			
User Costs	109	158	185
Direct Costs	51	51	51
Total Costs	233	282	309
Net Benefits	103	53	26
Benefit/Cost Ratio	1.44	1.19	1.08

Table 2-3

NEB Benefit-cost Analysis of Amoco/ Con Ed's Export Proposal
(millions of 1988$, discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Gas Exports	284	371
By-product Revenue	40	59
Total Benefits	324	430
Costs		
Total Incremental Production Costs	262	362
Transportation Costs		
Facilities Costs	53	53
Operating Costs	3	3
Total Costs	318	419
Net Social Benefits	6	11
Benefit/Cost Ratio	1.02	1.03

reasonably foreseeable Canadian requirements. Under this procedure the Board considers the EIA and complaints by Canadian gas-users taking into account current conditions in Canadian gas markets. In this regard, the Board noted the absence of any complaints or opposition to the proposed export. Amoco/Con Ed submitted an EIA which demonstrated that the proposed exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters, the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, transportation arrangements, gas sales contracts, and the expected net benefits to Canada associated with the proposed export.

In its assessment of gas supply the Board reviewed Amoco/Con Ed's estimates of the reserves and productive capacity of Amoco and Amoco Resources and compared these estimates with its own. The Board noted that Amoco/Con Ed intends to rely on the corporate gas surplus of Amoco and Amoco Resources to satisfy the proposed exports or to make up any potential shortfalls in productive capacity. The Board was satisfied with Amoco/Con Ed's supply position.

With respect to Amoco/Con Ed's evidence on markets and contractual arrangements, the Board believes that the proposed export to Con Ed will occur at a high load factor. Furthermore, the Board is satisfied that the Amoco/Con Ed Gas Purchase Contract includes terms and conditions that will permit sufficient flexibility to ensure responsiveness to changing market conditions as well as to ensure an adequate level of take.

The Board's review of the net benefits to Canada expected to result from Amoco/Con Ed's proposed export shows that the project will likely generate net benefits to Canada.

Table 2-4

NEB Sensitivity Analyses of Amoco/Con Ed's Export Licence Application
(Net benefits in millions of 1988$)

	Low Oil Price Scenario	**High Oil Price Scenario**
Control Case (R/P Ratio = 12)	5.81	11.10
Different Discount Rates		
6% Discount Rate	(10.07)	(15.32)
10% Discount Rate	9.85	18.66
Load Factor Sensitivities		
85% Load Factor	8.40	13.33
90% Load Factor	7.86	12.71
Different Gas Prices		
10% Higher	21.39	27.33
10% Lower	(12.15)	(6.34)
20% Higher	34.83	43.30
20% Lower	(31.13)	(25.58)
No Facilities Credit	(7.34)	(2.00)
Different Supply Costs		
20% Higher	(20.94)	(23.05)
20% Lower	34.47	4.50
R/P Ratio = 15	(19.23)	(29.00)
Different Demand Forecasts		
Export @ 1.2 EJ/yr	12.36	36.00
Export @ 1.8 EJ/yr	(7.24)	(2.60)

ICG Utilities (Ontario) Ltd

3.1 Application Summary

ICG Ontario, by application dated 10 February 1989, requested, pursuant to Part VI of the Act, a licence to export natural gas at Sprague, Manitoba for subsequent reimport at Rainy River, Ontario. Ultimately, the gas would be consumed at its cogeneration facility at Fort Frances, Ontario.

ICG Ontario will purchase its required gas supplies in Alberta and Saskatchewan for transportation through the NOVA, TransGas Limited ("TransGas") and TransCanada systems for delivery to ICG Transmission Holdings Ltd. ("ICG Transmission") at Spruce, Manitoba. ICG Transmission will, in turn, transport the gas to the international border at Sprague, Manitoba for delivery to Inter-City Minnesota Pipelines Ltd. ("Minnesota Pipelines") which will transport the export volumes to Rainy River, Ontario. From this point of reimport, the gas will be transported by ICG Transmission to Fort Frances, Ontario.

The proposed ICG Ontario cogeneration facility at Fort Frances will consume the reimported natural gas, producing steam for sale to Boise Cascade Canada Ltd. ("Boise Cascade") and electricity for sale to Ontario Hydro.

The proposed terms and conditions of the applied-for licence are as follows:

Term	- 1 November 1990 to 31 October 2005 (15 years)
Point of Export	- Sprague, Manitoba
Point of Reimport	- Rainy River, Ontario
Maximum Daily Quantity	- 640.0 10^3m^3 (22.6 MMcf)
Maximum Annual Quantity	- 210.0 10^6m^3 (7.4 Bcf)
Maximum Term Quantity	- 3 150.0 10^6m^3 (111.2 Bcf)

3.2 Complaints Procedure

ICG Ontario's proposal to export gas for reimport did not involve a net export of gas. Consequently, the complaints procedure is not applicable to this proposed arrangement.

3.3 Export Impact Assessment

By letter dated 10 March 1989 the Board granted ICG Ontario exemption, under Part VI of the Act, from filing an EIA on the grounds that no net exports will take place.

3.4 Gas Supply

3.4.1 Supply Contracts

ICG Ontario's Natural Gas Sales Agreement with ICG Resources Ltd. ("ICG Resources") and its Gas Sales Agreement with North Canadian Marketing Inc. ("North Canadian Marketing") provide for each company to supply ICG Ontario with approximately 1 575 10^6m^3 (56 Bcf) over 15 years. The agreements also include a provision for a one-time increase or decrease in the daily contract quantity ("DCQ") by up to ten percent. ICG Resources has dedicated reserves from ten areas in Alberta, and North Canadian Marketing has dedicated lands in the Hatton/Bigstick area of Saskatchewan.

3.4.2 Reserves

Table 3-1 shows that the Board's estimate of ICG Ontario's contracted remaining marketable gas reserves is almost identical to that of ICG Ontario and exceeds the applied-for volume by approximately 38 percent. Saskatchewan gas makes up the largest portion of each estimate; however, it is ICG Ontario's intention to supply the gas equally from Alberta and Saskatchewan. In this regard, the Board notes that its estimate of Alberta reserves is about 18 percent lower than the requirements for Alberta gas.

In its analysis of ICG Ontario's gas supply, the

Board recognized 35 gas pools in Alberta and one in Saskatchewan.

ICG Ontario's estimate of reserves for its interest in the gas pools in Alberta is 1 580 10^6m^3 (56 Bcf). The Board's estimate for these pools is 1 294 10^6m^3 (46 Bcf). These are generally small pools distributed throughout the province, mainly in Cretaceous sands.

For 18 pools, the Board's estimate of pool area averaged 62 percent of ICG Ontario's estimate because the Board assigned a smaller area per pool than the 256 hectares used by ICG Ontario. Additionally, the Board's estimate of net pay for 21 pools averaged 60 percent of ICG Ontario's estimate.

ICG Ontario's estimate of reserves for its interest in the large Hatton Second White Specks pool in Saskatchewan is 2 820 10^6m^3 (100 Bcf), while the Board's estimate is 3 070 10^6m^3 (108 Bcf). This eight percent variance is the result of small differences in assignment of marketable reserves per section.

In summary, the Board's estimate of total reserves is similar to that of ICG Ontario, although the Board's estimate of Alberta reserves is less than both ICG Ontario's estimate and the required Alberta supply.

Table 3-1

Comparison of Estimates of ICG Ontario's Remaining Marketable Gas Reserves with the Applied-for Term Volume
10^6m^3 (Bcf)

Area	ICG[1]	NEB[2]	Applied-for Term Volume
Alberta	1 580 (56)	1 294 (46)	1 575 (56)
Saskatchewan	2 820 (100)	3 070 (108)	1 575 (56)
Total	4 400 (156)	4 364 (154)	3 150 (112)

1 as of May, 1989
2 as of December, 1988

3.4.3 Productive Capacity

A comparison of the Board's and ICG Ontario's projections of productive capacity with the applied-for volumes is shown in Figure 3-1. In order to determine productive capacity from the Saskatchewan reserves, a decline analysis was conducted by ICG Ontario. The Board concurs with this methodology and has adopted ICG Ontario's projection of productive capacity from these reserves. The Board, therefore, agrees that the portion of requirements to be supplied by Saskatchewan gas will be fully met. Shortfalls illustrated in Figure 3-1 result from ICG Ontario's Alberta reserves being insufficient to meet their portion of the productive capacity requirements.

With respect to productive capacity from the Alberta reserves, the Board's analysis suggests potential deficiencies may begin in 1996. ICG Ontario projects deficiencies beginning in 1997. In order to meet its total requirements, ICG Ontario would have to supplement its Alberta reserves.

The Board notes that the Alberta and Saskatchewan producers have agreed to backstop each other's supply.

Views of the Board

The Board's estimate of reserves and productive capacity from Alberta reserves indicates a potential shortfall. However, in light of the backstopping arrangements between Alberta and Saskatchewan producers, the Board is satisfied with ICG Ontario's gas supply.

3.5 Energy Removal Authorization

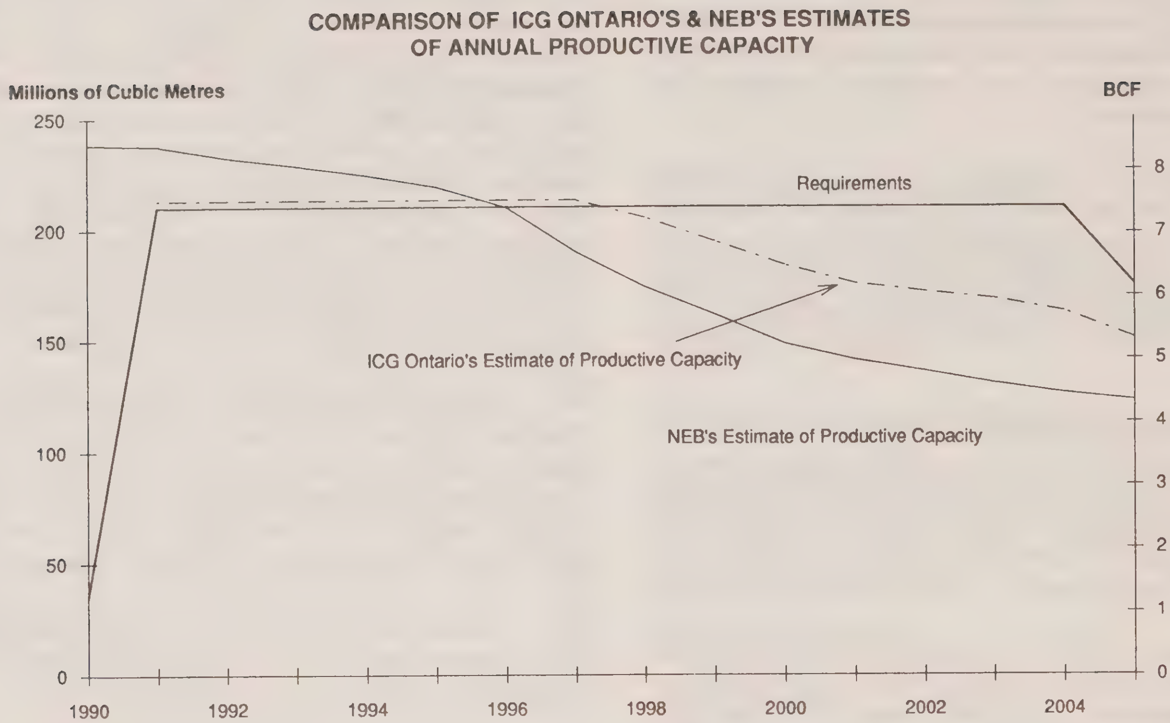
An application has been filed with the ERCB for an Alberta removal permit. A decision is pending.

With respect to the Saskatchewan reserves, the Saskatchewan Department of Energy and Mines has indicated that reserves and deliverability have been demonstrated to its satisfaction and that a removal permit will be forthcoming when downstream regulatory approvals are secured.

3.6 Market

ICG Ontario indicated that it had contracted with Fluor Daniel Canada Inc. to build a $100 million cogeneration facility at Fort Frances, Ontario. The

FIGURE 3-1



facility will consist of a 50 megawatt ("MW") gas-fired turbine, a 50 MW steam turbine generator, a waste heat recovery boiler, a gas-fired package boiler and all related auxiliary equipment. ICG Ontario estimates that this cogeneration facility will be completed in the fourth quarter of 1989.

ICG Ontario indicated that the steam produced at the cogeneration facility would be sold to Boise Cascade pursuant to a 15-year contract under which Boise Cascade will purchase all of its steam requirements for its Fort Frances, Ontario operation. Power produced at the cogeneration facility would be sold to Ontario Hydro pursuant to a 15-year term contract.

3.7 Contractual Arrangements

Alberta and Saskatchewan gas for the export/import licence sought by ICG Ontario would be transported by TransCanada for delivery to ICG Transmission at Spruce, Manitoba. From that point the gas would be transported to Sprague, Manitoba for export onto the Minnesota Pipelines system. From Sprague the gas would be transported approximately 48 miles east for import into Canada at Rainy River, Ontario for delivery by ICG Transmission at Fort Frances, Ontario.

ICG Ontario indicated that NOVA and TransGas had agreed to execute firm transportation contracts to transport the gas to TransCanada's facilities commencing no later than 1 November 1990. ICG Ontario entered into a transportation precedent agreement on 14 April 1989 with TransCanada to provide for transportation of the gas on its system.

ICG Ontario has also entered into a precedent agreement with ICG Transmission and Minnesota Pipelines for the required transportation services in Canada and the U.S. from Spruce, Manitoba to Fort Frances, Ontario.

Views of the Board

The Board is satisfied that ICG Ontario will have the necessary transportation capacity available to

it for the transportation of the volumes proposed for use in its Fort Frances cogeneration facility.

3.8 Benefit-cost Analysis

By letter dated 10 March 1989, the Board granted ICG Ontario exemption, under Part VI of the Act, from filing a benefit-cost analysis on the grounds that no net exports will take place.

3.9 Disposition

The Board has decided to issue a gas export and import licence to ICG Ontario. In order for the licence to take effect Governor in Council approval thereof is required. Appendix II contains the terms and conditions of the licence including a condition that states that the term of the licence shall commence on the date that Governor in Council approval is received and shall end on 31 October 1991, unless exports commence under the licence on or before 31 October 1991, in which case the term will end on 31 October 2005. The Board has also included a condition requiring that all gas exported at Sprague, Manitoba be reimported at Rainy River, Ontario.

In reaching its decision the Board assessed a number of public interest factors, including gas supply, markets, and transportation arrangements.

In its assessment of gas supply, the Board reviewed ICG Ontario's estimates of reserves and productive capacity and compared those estimates with its own. The Board's reserves estimates were similar to those submitted by ICG Ontario but indicated that Alberta reserves were slightly less than requirements from Alberta supply while Saskatchewan reserves were more than ample to supply requirements. Since it is ICG Ontario's intention to rely equally on Alberta and Saskatchewan supplies to serve the proposed cogeneration plant, the potential for a productive capacity shortfall from Alberta reserves exists. However, the Board is satisfied that backstopping arrangements in place between the Alberta and Saskatchewan producers provide ICG Ontario with adequate gas supply.

With respect to ICG Ontario's evidence on markets and transportation arrangements, the Board believes that the proposed export/import, which will fuel the Fort Frances cogeneration plant, will occur at a high load factor. Furthermore, the Board is satisfied that ICG Ontario will have all necessary transportation arrangements in place.

Chapter 4

Indeck Gas Supply Corporation

4.1 Application Summary

By application dated 14 February 1989, as amended, Indeck sought, pursuant to Part VI of the Act, a new natural gas export licence with a term of 15 years commencing the later of 1 November 1990 or the date of first deliveries.

The gas proposed for export would be used to fuel two cogeneration projects, one located near the town of Oswego, New York to be owned and operated by Indeck Energy Services of Oswego, Inc. ("Indeck Oswego"), the other, a project located in the town of Tonawanda, New York to be owned and operated by Indeck-Yerkes Energy Services, Inc. ("Indeck-Yerkes").

Indeck applied for a licence with the following terms and conditions:

Term	- 1 November 1990 to 31 October 2005 (15 years)
Point of Export	- Niagara Falls, Ontario
Maximum Daily Quantity	- 810.0 10^3m^3 (28.6 MMcf)
Maximum Annual Quantity	- 293.0 10^6m^3 (10.3 Bcf)
Maximum Term Quantity	- 3 500.0 10^6m^3 (123.5 Bcf)

The gas proposed for export would be produced in Alberta and Saskatchewan under purchase agreements with various producers. Gas produced in Alberta would be transported on the NOVA and TransCanada systems for delivery to Niagara Falls, Ontario. Gas produced in Saskatchewan would be delivered through a Saskatchewan pipeline owned by Bow Valley Industries Ltd. ("BVI") to the TransCanada system and then to the export point.

Gas destined for the Indeck Oswego project would be transported by National Fuel to the facilities of CNG Transmission Corporation ("CNG") on the proposed Niagara Spur Loop Line ("Niagara Spur"). CNG in turn would deliver the gas to the distribution facilities of Niagara Mohawk Power Corporation ("Niagara Mohawk") for ultimate transportation to the cogeneration plant.

The Indeck-Yerkes supply would be transported from Niagara Falls by National Fuel on the proposed Niagara Spur to existing National Fuel facilities at East Aurora, New York for redelivery to National Fuel Gas Distribution Corporation ("National Distribution") in Tonawanda, New York for ultimate transportation to the cogeneration plant.

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an EIA; and other factors which the Board considers relevant in its determination of the public interest including, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements, markets, and net benefits to Canada.

4.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an

opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Indeck export proposal.

4.3 Export Impact Assessment

Indeck estimated the annual volume of applied-for exports to represent 0.3 percent of marketable Canadian gas production in 1987. The total volume of proposed exports over the licence term was estimated by Indeck to constitute 0.15 percent of marketable gas reserves in western Canada in 1987. Indeck concluded that since the volume of applied-for exports was small, it would not reduce the ability of Canadian gas producers to satisfy domestic and export requirements.

Indeck held the view that in the long run Canadian natural gas prices will reflect overall North American conditions. In this regard, Indeck expected the small volume of exports to have only a negligible impact on natural gas prices paid by Canadians.

Views of the Board

The Board agrees with Indeck's overall conclusion that the applied-for export volumes should have little impact on Canadian production, consumption and prices of natural gas and that Canadian energy users would not have any difficulty in meeting their future energy requirements.

4.4 Gas Supply

4.4.1 Supply Contracts

Indeck has separate gas supply arrangements for the Indeck Oswego and Indeck-Yerkes projects. The Board has, therefore, examined Indeck's supply on a project-specific basis.

The Indeck Oswego project would be supplied with Alberta gas under Indeck's 15-year Gas Purchase Agreement with four producers, namely, Northstar Energy Corporation ("Northstar"), Chesapeake Resources Ltd. ("Chesapeake"), Inverness Petroleum Ltd. ("Inverness") and Universal Explorations Ltd.("Universal"). In addition, a 15-year Gas Purchase Agreement was executed with BVI to provide gas from the province of Saskatchewan.

The Indeck-Yerkes project would be supplied with gas from the province of Saskatchewan under a separate Gas Purchase Agreement with BVI. Northstar would provide the balance of the required volume for the Indeck-Yerkes project from its Alberta reserves.

4.4.2 Established Reserves

a) Indeck Oswego Project

The project's reserves from the province of Saskatchewan would be provided from the large Hatton Milk River Medicine Hat pool. Table 4-1 shows that there is not a significant difference between the Board's and Indeck's estimates of these reserves. However, it should be noted that the estimates are for two different points in time and that there appear to be differences in estimates of cumulative production to date.

Table 4-1

Indeck Oswego Project: Comparison of Estimates of Indeck's Remaining Marketable Gas Reserves with the Applied-for Term Volume
10^6m^3 (Bcf)

Province	Indeck[1]	NEB[2]	Applied-for Term Volume
Alberta	1 236 (44)	938 (33)	1 021 (36)
Saskatchewan[3]	13 428 (474)	13 330 (471)	821 (29)
Total	14 664 (518)	14 268 (504)	1 842 (65)

1. estimate to November 1990 (estimated cumulative production is 1 849 10^6m^3)
2. as of December 1988 (cumulative production for the province of Saskatchewan is 2 220 10^6m^3)
3. BVI's total uncommitted supply in Hatton Field, which will also supply the Indeck-Yerkes project.

In its analysis of Indeck's gas supply for the Indeck Oswego project, the Board recognized 30 gas pools in the province of Alberta and one in the province of Saskatchewan. With respect to the Alberta reserves, the Board's estimate is about 24 percent lower than Indeck's estimate and slightly lower than the applied-for volumes. The differences are due primarily to interpretation of net pay and pool area. These are generally small pools found in the Cretaceous, Jurassic and Devonian zones.

In summary, the Board's estimate of Indeck Oswego-related reserves in the province of Saskatchewan is similar to Indeck's estimate and far exceeds contractual requirements. However, the Board notes that its estimate of Indeck Oswego-related reserves in the province of Alberta is lower than the estimate of Indeck and is lower than contractual requirements.

b) Indeck-Yerkes Project

Gas supply for the Indeck-Yerkes project would be provided from the Hangingstone Upper Mannville A pool in the province of Alberta and the Hatton Milk River Medicine Hat pool in the province of Saskatchewan.

Table 4-2

Indeck-Yerkes Project: Comparison of Estimates of Indeck's Remaining Marketable Gas Reserves with the Applied-for Term Volume

10^6m^3 (Bcf)

Province	Indeck[1]	NEB[2]	Applied-for Term Volume
Alberta	746 (26)	562 (20)	685 (24)
Saskatchewan[3]	13 428 (474)	13 330 (470)	974 (34)
Total	14 174 (500)	13 892 (490)	1 659 (58)

1. estimate to November 1990 (cumulative production estimate is 1 849 10^6m^3)
2. as of December 1988 (cumulative production for the province of Saskatchewan is 2 220 10^6m^3).
3. BVI's total uncommitted supply in Hatton Field, which will supply both projects.

Table 4-2 shows that the Board's estimate of dedicated reserves for the Alberta gas is 25 percent lower than Indeck's estimate and 18 percent less than the applied-for volumes. A large difference in net pay values for the pool accounts for the majority of the difference in estimates of reserves.

The Board's estimate of Indeck-Yerkes-related reserves in the province of Saskatchewan is very similar to that of Indeck. However, as with the Indeck Oswego project, the estimates are for two different points in time and there appear to be differences in estimates of cumulative production.

In summary, the Board's estimate of Indeck-Yerkes-related reserves in the province of Saskatchewan far exceeds contractual requirements, but its estimate of Alberta reserves for Indec-Yerkes is lower than Indeck's estimate and lower than contractual requirements.

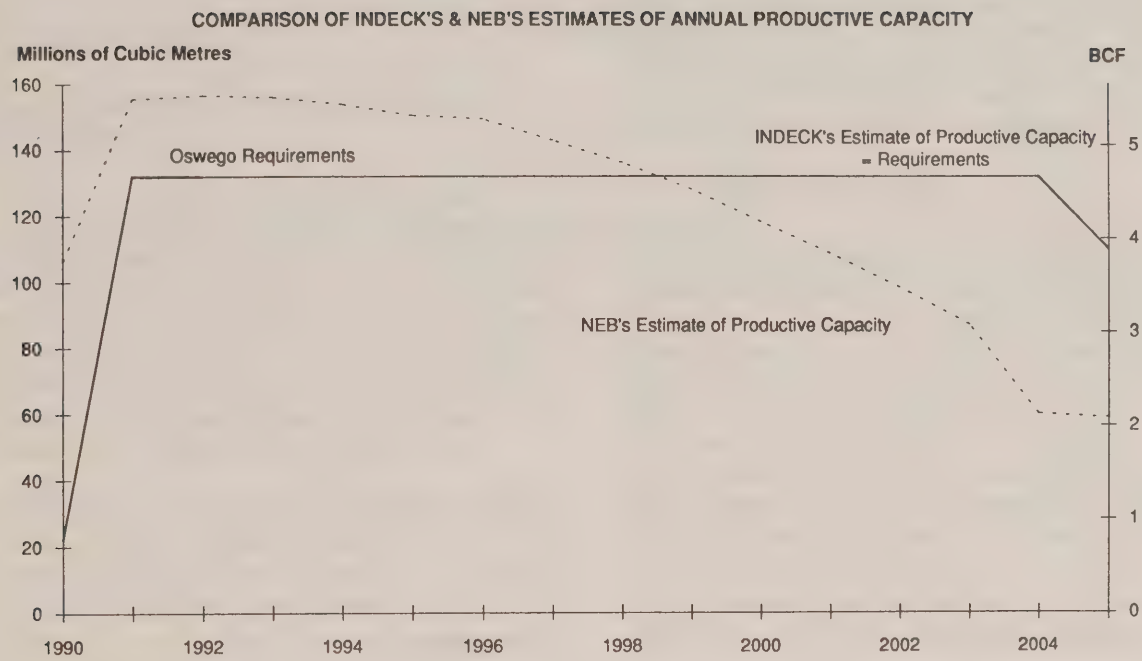
4.4.3 Productive Capacity

a) Indeck Oswego Project

Figure 4-1 compares the Board's and Indeck's projections of productive capacity with the proposed export volumes for the Indeck Oswego project (including fuel on the TransCanada system). The Board assumed that BVI could easily meet the contract rate, given the large volume of reserves in the province of Saskatchewan. For analytical purposes, the Board therefore tracked the supply to the requirements in the province of Saskatchewan and for that reason any excess or deficiency in productive capacity appearing in Figure 4-1 relates to Alberta reserves.

The Board's projection suggests that a shortfall will exist commencing in approximately 1999. Indeck was confident that it could meet requirements throughout the proposed term and, in its evidence, presented daily production rates in excess of requirements. The difference in outlook is attributable to the difference in estimates of Alberta reserves.

FIGURE 4-1

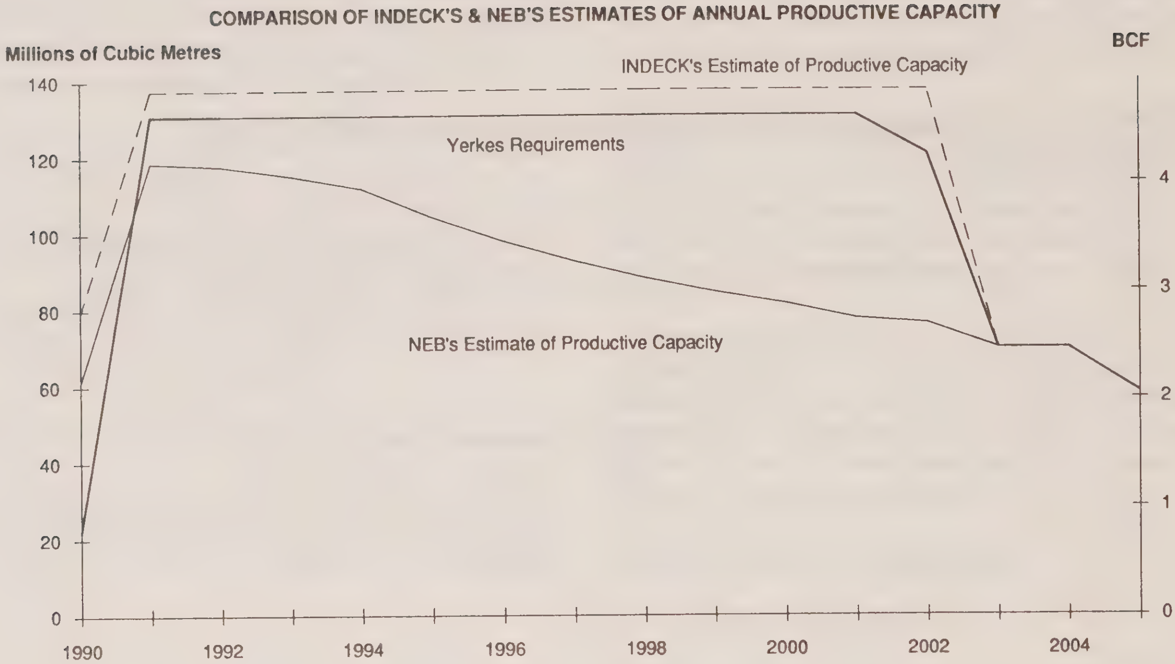


b) Indeck-Yerkes Project

Figure 4-2 compares the Board's and Indeck's projections of productive capacity with the proposed export volumes for the Indeck-Yerkes project (including fuel on the TransCanada system). As with the Indeck Oswego project, the Board tracked supply to the requirements in the province of Saskatchewan, and any excess or deficiency in productive capacity stems from reserves in the province of Alberta.

Indeck's projection suggests adequate productive capacity throughout the proposed export term. However, the Board's projection indicates insufficient productive capacity throughout the entire term. Again, the difference in outlook is attributable to the difference in estimates of reserves in the province of Alberta.

FIGURE 4-2



Views of the Board

The Board is satisfied that the portion of the supply needed from the province of Saskatchewan for both the Indeck Oswego and Indeck-Yerkes projects can be met. However, the Board is of the view that Indeck has not demonstrated sufficient supply to meet the Alberta portion of the supply needed throughout the proposed term for either project. Therefore, the adequacy of supply would be contingent upon Indeck's ability to acquire additional reserves to meet its Alberta requirements. In this regard, the Board notes that Indeck has not offered any backstopping arrangements, nor any cross-dedication of reserves from the province of Saskatchewan to indicate the ability to satisfy its total requirements.

4.5 Energy Removal Authorizations

Energy removal authorizations from Alberta and the province of Saskatchewan have been applied for. Decisions are pending.

4.6 Markets

Indeck proposes to export natural gas to Indeck Oswego and to Indeck-Yerkes for use in two cogeneration facilities which are to be constructed in Oswego, New York and Tonawanda, New York respectively.

Indeck Oswego and Indeck-Yerkes are subsidiaries of Indeck Energy Services, Inc., an Illinois corporation engaged in developing, owning and operating cogeneration projects. Indeck Oswego and Indeck-Yerkes would operate the proposed cogeneration facilities and secure all related permits and authorizations (including transportation service arrangements) in the United States.

The Indeck Oswego facility would produce about 50.4 MW of electricity for sale to Niagara Mohawk. The steam produced would be sold under a 20-year contract to International Paper Company.

The Indeck-Yerkes facility would produce about 53 MW of electricity for sale to Niagara Mohawk. Steam produced at the facility would be sold to E.I. Dupont de Nemours and Company under a 20-year contract.

Both facilities have QF status and would therefore have assured electrical sales to Niagara Mohawk.

4.7 Contractual Arrangements

4.7.1 Transportation

Indeck Oswego/Indeck-Yerkes Canadian Transportation

Gas produced in Alberta would be transported by NOVA to the TransCanada system for delivery to Niagara Falls, Ontario. Indeck stated that its participating producers had each secured NOVA capacity for the majority of the requirements and expected to finalize remaining NOVA transportation shortly. Indeck has executed Precedent Agreements with TransCanada for 15-year firm transportation arrangements for each project.

Gas produced in the province of Saskatchewan would enter the TransCanada system at Bayhurst II, Saskatchewan through a pipeline owned by BVI and therefore there would be no requirement for any other transportation in the province of Saskatchewan.

Indeck Oswego U.S. Transportation

Indeck Oswego has entered into a Precedent Agreement with National Fuel for a 15-year transportation contract to transport gas from the international boundary to a point of interconnection with the CNG system at Marilla, New York. All transportation would take place on the Niagara Spur facilities, yet to be constructed. Those facilities await the FERC's approval.

From Marilla, New York, CNG would transport the gas, under a proposed firm transportation contract, to an interconnection with Niagara Mohawk's distribution facilities in Oswego County, New York. From this point, Niagara Mohawk would transport the gas to the Indeck Oswego facility through a proposed 13-mile pipeline extension. Indeck Oswego and Niagara Mohawk have entered into an Agreement in Principle for the proposed transportation arrangements.

Indeck-Yerkes U.S. Transportation

From Niagara Falls, Ontario, the gas would be transported through the proposed Niagara Spur by National Fuel for delivery to National Fuel's existing facilities at East Aurora, New York. Indeck-Yerkes and National Fuel have executed a Precedent Agreement in this regard.

At East Aurora, New York, National Fuel would deliver the gas to National Distribution for ultimate delivery to the Indeck-Yerkes facility at Tonawanda, New York. Indeck-Yerkes and National Distribution have entered into an Outline of Basic Understanding for transportation services.

4.7.2 Sales Contracts

Indeck executed a separate Gas Sales and Purchase Agreement with each of Indeck Oswego and Indeck-Yerkes (each dated 27 December 1988) that provides for the sale of up to 397 10^3m^3 (14 MMcfd) per day and 127.5 $10m^6m^3$ (4.5 Bcf) per year for 15-year terms commencing 1 January 1989. The agreements would remain in effect year to year thereafter until terminated by either party upon 12 months notification. Each of the agreements provides for gas sales at a price equal to Indeck's costs to purchase the gas in Alberta and Saskatchewan plus the cost to transport the gas on the TransCanada system to Niagara Falls, Ontario.

The terms and conditions governing the export sales are those included in the various Gas Purchase Agreements between Indeck and the five participating producers supplying gas to the projects from Alberta and the province of Saskatchewan.

(a) Indeck Oswego Gas Sales Arrangement

Under a single contract dated 31 January 1989 (referred to as the Indeck Oswego Alberta Agreement), Indeck has agreed to purchase a MDCQ up to 200.5 10^3m^3 per day (7.1 MMcfd) from four producers to serve the Indeck Oswego facility as follows:

Producers (Indeck Oswego Alberta Agreement)	Pro-Rata Share of MDCQ 10^3m^3 (MMcf)
Chesapeake	- 28.2 (1.0)
Inverness	- 29.8 (1.1)
Northstar	- 29.8 (1.1)
Universal	- 112.7(4.0)

The Indeck Oswego Alberta Agreement includes the following principal terms and conditions:

- 15-year term commencing on or about 1 November 1990;
- 100 percent annual take or pay obligation;
- dedication of reserves to maintain a rolling 5-year average of daily deliverability up to the MDCQ;
- guarantee from Indeck Oswego of all of Indeck's obligations under the agreement;
- delivery point at the Alberta/Saskatchewan border inlet to TransCanada's system;
- price for gas shall be the monthly "Market Price" plus the "Producer's Bonus" for the month; the "Market Price" is set at \$U.S. 1.67/Mcf including all intraprovincial transportation costs, taxes, royalties and related losses or unaccounted-for retainage;
- effective 1 January 1991 and on each 1 January thereafter the "Market Price" will escalate by 3 percent; and
- the "Producer's Bonus" will be equal to \$U.S. 0.04/Mcf for each \$U.S. 0.001 per kilowatt-hour ("Kwh") that Niagara Mohawk's power purchases from the Oswego facility exceed the floor rate for the preceding calendar month. The "Producer's Bonus" is limited to a maximum of \$U.S. 0.12/Mcf in 1992, escalating to \$U.S. 1.08/Mcf in 1995, \$U.S. 2.82/Mcf in 2000 and \$U.S. 3.75/ Mcf in 2004.

The Indeck Oswego facility will also acquire gas supply through a Gas Purchase Agreement dated 13 February 1989, as amended, between Indeck and BVI (referred to as the Indeck Oswego Saskatchewan Agreement), for supplies to be produced in the province of Saskatchewan. This agreement includes the following principal terms and conditions:

- 15-year term commencing on or about 1 November 1990;
- minimum daily quantity of 161.2 10^3m^3 (5.7 MMcf);
- 100 percent annual take or pay obligation;
- guarantee from Indeck Oswego of all of Indeck's obligations under the agreement;
- delivery point at the inlet of TransCanada's system at Bayhurst II, Liebenthal, Saskatchewan; and
- pricing and escalation conditions are the same as those contained in the Indeck Oswego Alberta Agreement.

(b) Indeck-Yerkes Gas Sales Arrangements

Indeck has signed two Gas Purchase Agreements to supply the Indeck-Yerkes facility. The first is an agreement dated 9 March 1989 with Northstar for Alberta gas supplies (referred to as the Indeck-Yerkes Alberta Agreement). The salient terms and conditions of this agreement are as follows:

- 18-year term commencing on or about 1 November 1990;
- maximum daily quantity of 181.3 10^6m^3 (6.4 MMcf);
- maximum annual quantity of 62.3 10^6m^3 (2.2 Bcf);
- delivery point is the inlet to TransCanada's system at the Alberta/Saskatchewan border;
- price for gas shall be a single lump-sum payment of \$U.S. 13.65 million payable on 1 November 1989 for approximately 736.5 10^6m^3 (26.0 Bcf) plus a monthly operating charge equal to \$U.S. 0.315/MMBtu as of 1 January 1988 and shall change each 1 January thereafter commencing in 1989 by multiplying the then current operating charge by the higher of 1.05 or by the annual increase in the U.S. GNP Implicit Price Deflator; and
- Indeck will also pay Northstar for all royalties and transportation costs including levies under the Alberta Take or Pay Cost Sharing Act incurred by Northstar in delivering gas to the point of delivery.

The second Gas Purchase Agreement for the Indeck-Yerkes facility is an agreement dated

13 March 1989 between Indeck and BVI for gas produced in the province of Saskatchewan, (referred to as the Indeck-Yerkes Saskatchewan Agreement). A summary of the principal terms and conditions follows:

- 15-year term commencing on or about 1 November 1990;
- minimum daily quantity of 191.3 10^3m^3 (6.7 MMcf);
- 100 percent annual take or pay obligation;
- guarantee from Indeck-Yerkes of all of Indeck's obligations under the agreement;
- delivery point at the inlet of TransCanada's system at Bayhurst II, Liebenthal, Saskatchewan;
- pricing conditions are the same as those contained in the Indeck Oswego Alberta Agreement; and
- escalation factor is set at 4 percent per year commencing on 1 January 1991.

Views of the Board

The terms of the Indeck Oswego Alberta, Indeck Oswego Saskatchewan and Indeck-Yerkes Saskatchewan Agreements provide that all intraprovincial costs be paid by the producers out of the proceeds of the export sales revenues.

The Board accepts that initially all intraprovincial costs are being paid by the producers out of export revenues received. However, the Board is concerned that, under the fixed escalation rates of 3 and 4 percent per year for the export price, intraprovincial transportation and distribution costs, royalties, taxes and duties assessed on the gas could escalate at a higher rate than export revenues. In the event that the producer bonus payment component of the price was less than forecasted, producers could experience a decline in their netback prices over time.

Under the Indeck-Yerkes Alberta Agreement with Northstar, the operating fee, set at $U.S. 0.315/MMBtu, is designed to recover all operating costs within Alberta and would be escalated annually. As well, Indeck would pay Northstar for all crown royalties and associated NOVA costs.

Assuming that Northstar's operating fee escalates at a rate comparable to the Board's forecast of inflation, the contract would likely provide continued recovery of these costs. With respect to NOVA costs, royalties, taxes and duties, the Board notes that these costs would be paid by Indeck under the terms of the agreement.

Under the export Gas Sales and Purchase Agreements, the U.S. buyers agree to pay for gas at either of the Alberta or Saskatchewan delivery points plus all transportation costs to the international boundary.

Although this is not the usual method for collecting fixed costs of transportation, the Board is of the view that interprovincial and intraprovincial transportation costs could be recovered.

Indeck's sales arrangements under the Indeck Oswego Alberta and Indeck Oswego Saskatchewan Agreements include provision for a three percent annual price escalator while under the Indeck-Yerkes Saskatchewan Agreement the escalation rate is four percent. All of these agreements include a "Producer's Bonus" payment which is designed to reflect increases in electricity prices received by the cogeneration plants. The Indeck-Yerkes Alberta Agreement provides for an up-front lump-sum payment of $U.S. 13.65 million which, according to Indeck, represents the time-value of the gas to be exported.

The Board notes that cogeneration plants can be viable only if the sum of their gas and other costs can be recovered through the prices they receive for their electricity, and these prices are determined by regulatory arrangements in the United States. In many cases the gas prices paid by cogeneration plants are indexed to key alternative fuels and may also include bonuses that would be payable in the event that electric sales revenues are higher than pre-determined forecast levels. Given the dynamics normally associated with energy prices, the Board is concerned that the Indeck Oswego Alberta Agreement, the Indeck Oswego Saskatchewan Agreement and the Indeck-Yerkes Saskatchewan Agreement include fixed escalators over the contract term, particularly where these agreements do not provide for price renegotiation.

The export sales arrangements under the Indeck Oswego Alberta, Indeck Oswego Saskatchewan and Indeck-Yerkes Saskatchewan Agreements include 100 percent take or pay conditions for the volumes under contract, coupled with make-up rights. In addition, the agreements include provision for third-party sales for excess supplies under certain circumstances.

The Board is satisfied that the agreements provide reasonable assurance that volumes will be taken. In addition, the Board is aware that the power sales contracts with Niagara Mohawk ensure high load factor operations at the cogeneration facilities.

Indeck's up-front lump-sum payment, in the Indeck-Yerkes Alberta Agreement, would be a valuable resource to the Alberta producer for use to develop additional gas supplies. Given this arrangement, the Board is not concerned about the level of takes that would occur under the Agreements.

Producer support is evidenced by the various executed Gas Purchase Agreements.

4.8 Benefit-cost Analysis

As is stated in Subsection 4.7.2 of these Reasons for Decision, both of Indeck's Gas Sales and Purchase Agreements provide for gas sales at a price equal to Indeck`s original purchase price (from its Gas Purchase Agreements with its producers) plus transportation costs to Niagara Falls, Ontario. The Indeck Oswego Alberta and Saskatchewan Agreements have identical pricing terms, therefore there exists only one pricing mechanism for the Indeck Oswego project. However, the Indeck-Yerkes Alberta and Saskatchewan Agreements have different pricing provisions. Consequently, the Indeck-Yerkes project has two separate pricing mechanisms; one in respect of its Alberta supply and the other in respect of its Saskatchewan supply. Each of the three aforementioned pricing mechanisms has been separately analysed by the Board for benefit-cost purposes. The two Indeck-Yerkes benefit-cost analyses are referred to as Indeck-Yerkes/Northstar and Indeck-Yerkes/BVI, respectively, in recognition of the project's Alberta and Saskatchewan producers.

In response to a Board information request Indeck submitted a separate benefit-cost analysis for each of the three aforementioned pricing mechanisms.

Indeck Oswego

The benefit-cost analysis submitted by Indeck in support of the Indeck Oswego project indicated that this export would yield net benefits to Canada (see Table 4-3).

The Gas Sales and Purchase Agreement between Indeck and Indeck Oswego stipulates that the price will be computed as the sum of an adjusted base price ("ABP") plus a bonus. The base price of $U.S. 1.67/Mcf is escalated annually at three percent. The monthly bonus commences in 1992 and is equal to $U.S. 0.04/Mcf for each $U.S. 0.001/Kwh that Niagara Mohawk's purchase price exceeds a contractually-specified floor rate (subject to a ceiling). Indeck assumed that 20 percent of the maximum allowable bonus would be realized in the event of low oil prices and 80 percent with high oil prices. Indeck assumed a 100 percent load factor operation.

Indeck included by-product revenues in its analysis as an incremental benefit associated with this project, estimating that by-product revenues from Alberta gas would add ten percent to the revenue stream. In response to an information request, Indeck stated that it recognized that the supply cost estimates that it used already included a credit for by-product revenues. However, Indeck maintained that this did not in itself invalidate the inclusion of by-product revenues as a benefit in its analysis.

In its analyses, Indeck made two adjustments intended to translate the incremental private costs and benefits to a social basis. Its low oil price case benefit-cost analysis incorporates credits of $5.3 million for a social premium on foreign exchange earnings and $2.5 million reflecting the social opportunity cost of labour.

In its determination of the user cost associated with the sale to Indeck Oswego, Indeck based its forecast of total requirements on the projection of domestic demand found in the Supply/Demand Report plus already authorized exports. Indeck then considered its proposed export volumes to be incremental to the projection of authorized export volumes. Indeck argued that this was the appropri-

ate methodology to be used in estimating user cost since using a forecast of future exports rather than only authorized exports implicitly sets aside low user cost gas for future evergreened licences or for as yet unspecified exports.

Indeck estimated incremental facilities costs on the TransCanada system using data provided by TransCanada. Allowance was made for the incremental cost of transmission by others by including an estimate of incremental operating costs ($0.267/GJ). Although detailed information was not available, Indeck estimated NOVA incremental capital costs to be $6 million.

In summary, Indeck concluded that the Indeck Oswego project would likely yield positive net benefits to Canada.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

The Board used aggregate industry data to calculate by-product revenues and used a forecast of exports rather than simply currently licensed exports to calculate the TIPC (including user costs). The Board's estimates of by-product revenues in respect of the Indeck Oswego project are much higher than Indeck's in both the low and high world oil price scenarios because Indeck did not expect its Saskatchewan gas to produce by-products.

In estimating the incremental capital costs associated with the transportation of the proposed export, the Board has included a credit for the useful economic life of the facilities after the term of the exports.

In its benefit-cost analyses, the Board has not included a credit for the social opportunity cost of labour or a social premium on foreign exchange. As explained in Appendix I of these Reasons, the Board is not convinced that there are sufficient grounds to include such credits.

As also explained in Appendix I of these Reasons, the Board is of the view that cogeneration plants are unlikely to achieve a load factor in excess of 90 percent. Therefore, the Board has used a load factor of 90 percent in assessing the net benefits to Canada that would be associated with the Indeck Oswego project. Sensitivity tests were conducted at 85 and 95 percent load factors. Lower sales volumes would have the effect of reducing the revenues, the TIPC and the variable transportation costs.

The Board's assumptions regarding exchange and inflation rates also differ from those of Indeck. Indeck assumed an exchange rate of $ 0.813 U.S./Cdn for 1990-2005 and an inflation rate of 3.9 percent. The Board used inflation and exchange rates consistent with the Supply/Demand Report assumptions, so as to be consistent with other data used in its analyses. The Board's forecast of exchange rates results in a slightly higher gas price than forecasted by Indeck. However, this is offset to some extent by the Board's forecast of inflation rates which is higher than that used by Indeck.

In forecasting the bonus portion of the sales price, the Board did not adopt Indeck's assumptions that 20 and 80 percent of the maximum allowable bonus would be realized in the low and high cases, respectively. Although Indeck's methodology seems directionally correct, the Board is of the view that a more accurate estimate of the expected bonus can be made by actually forecasting the expected purchase price of electricity upon which the value of the bonus depends. The Board used a forecast of the purchase price of electricity as found in the New York State Public Service Commission ("NYSPSC") Opinion 88-13 and adjusted it for the low and high world oil price scenarios from the Supply/Demand Report. The resulting bonus is almost the same as that assumed by Indeck in the low oil price case but is lower than that assumed by Indeck in the high oil price case.

The Board's control case and sensitivity analyses (see Tables 4-4 and 4-5) indicate that the Indeck Oswego project is unlikely to generate net benefits to Canada under a wide range of plausible assumptions.

Table 4-3

Indeck's Benefit-cost Summary
Indeck Oswego
(millions of 1989$, discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Gross Natural Gas Revenue	80.1	109.4
TransCanada Toll Revenue	26.0	26.0
By-product Revenue	4.4	6.1
Sub-total	110.5	141.4
Social Premium on Foreign Exchange	5.3	6.8
Gross Benefits	115.8	148.2
Costs		
Capital	29.0	29.0
Operating	25.2	25.2
Total Transportation and Development	54.2	54.2
Labour Externality	2.5	2.5
Sub-total	51.7	51.7
Total User Cost	45.2	73.4
	96.9	125.1
Net Social Benefits	18.9	23.1
Benefit/Cost Ratio	1.20	1.18

Table 4-4

NEB Benefit-cost Summary
Indeck Oswego
(millions of 1989$, discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Gas Sales Revenue	71.6	81.6
TransCanada Toll Revenue	27.8	29.1
By-product Revenue	16.6	24.9
Total Benefits	115.9	135.6
Costs		
Transportation Costs		
Capital	23.7	23.6
Operating	1.1	1.1
TIPC	102.9	143.0
Total Costs	127.6	167.7
Net Social Benefits	(11.7)	(32.1)
Benefit/Cost Ratio	0.91	0.81

Table 4-5

NEB Sensitivity Analyses of
Indeck's Sales to Indeck Oswego
(millions of 1989$)

	Low Oil Price Scenario	High Oil Price Scenario
Control Case (R/P Ratio = 12)	(11.7)	(32.1)
Different Discount Rates		
6% Discount Rate	(19.6)	(47.1)
10% Discount Rate	(8.7)	(24.6)
Load Factor Sensitivities		
85% Load Factor	(10.9)	(30.0)
95% Load Factor	(12.3)	(33.6)
Different Bonus		
10% Higher	(6.4)	(24.8)
10% Lower	(16.6)	(38.9)
No Facilities Credit	(17.5)	(37.8)
Different Supply Costs		
20% Higher	(22.0)	(45.1)
20% Lower	(0.6)	(18.9)
R/P Ratio=15	(21.7)	(48.6)
Different Demand Forecasts		
Exports @ 1.2 EJ/yr	(9.7)	(22.2)
Exports @ 1.8 EJ/yr	(17.1)	(37.4)

Indeck-Yerkes/BVI

The benefit-cost analysis prepared by Indeck with respect to the BVI-related pricing mechanism of the Indeck-Yerkes project (summarized in Table 4-6) indicates that the proposed BVI-related sales to Indeck-Yerkes are expected to generate net social benefits to Canada.

The pricing terms in the Indeck-Yerkes Saskatchewan Agreement are identical to those set out in the Indeck Oswego Gas Purchase Agreements except that the base price of $U.S. 1.67/MMcf is escalated annually at 4 percent rather than 3 percent.

Indeck did not include by-product revenues as a benefit in its Indeck-Yerkes/BVI analysis because Indeck did not expect its Saskatchewan gas to generate any by-products.

In its analysis Indeck made two adjustments intended to translate the incremental private costs and benefits to a social basis. Its analysis incorporates credits totalling $3.8 million in the low oil

price case to reflect a social premium on foreign exchange earnings and the social opportunity cost of labour.

Indeck estimated incremental facilities costs on the TransCanada system using data provided by TransCanada. Allowance was made for the incremental cost of transmission by others by including an estimate of incremental operating costs ($0.267/GJ). There were no facilities costs allocated for transportation from the fieldgate to TransCanada's system.

Indeck's analysis indicated net benefits to Canada of $15.7 million and $17.7 million in its low and high price cases, respectively. Indeck concluded that the BVI-related sales to Indeck-Yerkes would likely provide net benefits to Canada.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

As explained in Appendix I of these Reasons, the Board used aggregate industry data to calculate by-product revenues and used a forecast of exports rather than simply currently licensed exports to calculate the TIPC (including user costs). The Board's estimates therefore include by-product revenues in respect of Indeck-Yerkes/BVI even though Indeck did not include any by-product revenues in its analysis.

In estimating the incremental capital costs associated with the transportation of the proposed export, the Board has included a credit for the useful economic life of the facilities after the term of the exports. The Board's analysis includes a facilities cost allocation for transportation from the fieldgate to TransCanada's system. This ensures that all incremental costs in Canada are captured in the analysis and that all projects are treated consistently and analyzed on a comparable basis.

In its benefit-cost analyses, the Board has not included a credit for the social opportunity cost of labour or a social premium on foreign exchange. As explained in Appendix I of these Reasons, the Board is not convinced that there are sufficient grounds to include such credits.

As is also explained in Appendix I of these Reasons, the Board is of the view that cogeneration plants are unlikely to achieve a load factor in excess of 90 percent. Therefore, the Board has used a load factor of 90 percent in assessing the net benefits to Canada that would be associated with the BVI-related sales to Indeck-Yerkes. Sensitivity tests were conducted at 85 and 95 percent load factors. Lower sales volumes would have the effect of reducing the revenues, the TIPC and the variable transportation costs.

The Board's assumptions regarding the exchange and inflation rates also differ from Indeck's. Indeck assumed an exchange rate of $ 0.813 U.S./Cdn for 1990-2005 and an inflation rate of 3.9 percent. The Board used inflation and exchange rates consistent with the Supply/Demand Report assumptions, so as to be consistent with other data used in its analyses. The Board's forecast of exchange rates results in slightly higher gas prices than forecasted by Indeck. However, this is offset to some extent by the Board's forecast of inflation rates which is higher than that used by Indeck.

As with its analysis of the Indeck Oswego project, the Board has estimated the bonus portion of the gas price to be realized under the Indeck-Yerkes Saskatchewan Agreement using a forecast of the purchase price of electricity upon which the value of the bonus depends.

The Board's control case and sensitivity analyses (see Tables 4-7 and 4-8) indicate that the BVI-related sales to Indeck-Yerkes are unlikely to generate net benefits to Canada under a wide range of plausible assumptions. The control case and each of the sensitivity analyses indicate negative results.

Table 4-6

Indeck Benefit-cost Summary
Indeck-Yerkes/BVI
(millions of 1989$, discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Gross Natural Gas Revenue	44.7	60.2
TransCanada Toll Revenue	13.7	13.7
By-product Revenue	0.0	0.0
Sub-Total	58.4	73.9
Social Premium on Foreign Exchange	2.9	3.7
Total Gross Social Benefits	61.3	77.6
Costs		
Capital	14.0	14.0
Operating	9.8	9.8
	23.8	23.8
Labour Externality	0.9	0.9
Total Social Cost of Transportation & Development	23.0	23.0
Total User Cost	22.7	36.9
Gross Social Costs	45.7	59.9
Total Net Social Benefits	15.7	17.7
Benefit/Cost Ratio	1.34	1.30

Table 4-7

NEB Benefit-Cost Summary
Indeck-Yerkes/BVI
(millions of 1989$, discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Gas Sales Revenue	40.0	45.2
By-product Revenue	7.9	11.8
TransCanada Toll Revenue	14.7	15.4
Total Benefits	62.5	72.4
Costs		
Transportation Costs		
Capital	12.5	12.5
Operating	0.6	0.6
TIPC	53.6	74.3
Total Costs	66.7	87.4
Net Social Benefits	(4.1)	(15.0)
Benefit/Cost Ratio	0.94	0.83

Table 4-8

NEB Sensitivity Analyses of the
BVI-related Sales to Indeck-Yerkes
(millions of 1989$)

	Low Oil Price Scenario	High Oil Price Scenario
Control Case (R/P Ratio = 12)	(4.1)	(15.0)
Different Discount Rates		
6% Discount Rate	(7.8)	(22.5)
10% Discount Rate	(2.9)	(11.4)
Load Factor Sensitivities		
85% Load Factor	(3.8)	(14.0)
95% Load Factor	(4.2)	(15.7)
Different Bonus		
10% Higher Index	(1.3)	(11.1)
10% Lower Index	(6.7)	(18.6)
No Facilities Credit	(7.2)	(18.1)
Different Supply Costs		
20% Higher	(9.6)	(21.9)
20% Lower	(1.8)	(8.0)
R/P Ratio=15	(9.4)	(23.7)
Different Demand Forecasts		
Exports @ 1.2 EJ/yr	(5.6)	(13.4)
Exports @ 1.8 EJ/yr	(7.1)	(17.8)

Indeck-Yerkes/Northstar

Indeck's benefit-cost analysis in respect of the Northstar-related sales to the Indeck-Yerkes project indicates that the proposed Northstar-related sales would likely generate net benefits to Canada (see Table 4-9).

The Indeck-Yerkes Alberta Agreement between Indeck and Northstar specifies that the buyer shall pay the seller a lump-sum up-front payment of $U.S. 13.65 million plus an operating charge. Indeck is also required to reimburse Northstar for all royalties paid by Northstar, all TOPGAS charges and NOVA transportation charges incurred in delivering the gas.

The lump-sum payment and the operating charge constrain the scope for fluctuations under the contract. In estimating the project revenues Indeck made assumptions regarding low and high world oil prices which pertain solely to the estimated royalties. The imputed low and high royalties are based on "floor" royalty provisions of 80 percent of the low and high Alberta field price from the Supply/Demand Report.

Indeck estimated by-product revenues for the Northstar-related sales to Indeck-Yerkes in the same manner as they were estimated for the Indeck Oswego project. The estimated by-product revenues amounted to $3.2 million (discounted at 8 percent) in the low oil price case and $4.1 million in the high oil price case.

Indeck made adjustments to its benefit-cost analysis to reflect the shadow prices of labour and the foreign exchange rate by including the following two credits:

- a social premium on foreign exchange of $2.1 million; and

- $0.6 million to reflect the social opportunity cost of labour.

Indeck estimated the user costs associated with Indeck-Yerkes/Northstar using the methodology that was used in its analysis of the Indeck Oswego project. Project-specific data were used to estimate the direct production costs.

Indeck based its estimates of TransCanada's incremental facilities costs on data provided by TransCanada. Indeck's allowance for the incremental operating costs of $0.267/GJ accommodated both the TransCanada operating costs and the incremental costs of transmission by others. Indeck estimated incremental capital and operating costs on NOVA to be $4 million and $0.05/GJ (1989$), respectively.

Indeck concluded that there would be a net social benefit to Canada from its Northstar-related sales to Indeck-Yerkes.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

As explained in Appendix I of these Reasons, the Board used aggregate industry data to calculate by-product revenues and used a forecast of exports rather than simply currently licensed exports to calculate the TIPC (including user costs). The Board's estimate of by-product revenues with respect to the Indeck-Yerkes/Northstar sale is higher than that of Indeck.

In estimating the incremental capital costs associated with the transportation of the Northstar-related volumes, the Board has included a credit for the useful economic life of the facilities after the term of the exports.

In its benefit-cost analyses, the Board has not included a credit for the social opportunity cost of labour or a social premium on foreign exchange. As explained in Appendix I of these Reasons, the Board is not convinced that there are sufficient grounds to include such credits.

As is also explained in Appendix I of these Reasons, the Board is of the view that cogeneration plants are unlikely to achieve a load factor in excess of 90 percent. Therefore, the Board has used a load factor of 90 percent in assessing the net benefits to Canada that would be associated with the Northstar-related sales to Indeck-Yerkes. Sensitivity tests were conducted at 85 and 95 percent load factors. Lower sales volumes would have the effect of reducing the revenues, the TIPC and the variable transportation costs.

The Board's assumptions regarding the exchange and inflation rates also differ from those of Indeck. Indeck assumed an exchange rate of $ 0.813 U.S./Cdn for 1990-2005 and an inflation rate of 3.9 percent. The Board used inflation and exchange rates consistent with the Supply/Demand Report assumptions, so as to be consistent with other data used in its analyses. The Board's forecast of exchange rates results in the variable component of the gas revenue being slightly higher in the Board's analysis than in that of Indeck. This variance is offset to some extent by Indeck's assumed 3.9 percent inflation rates which is lower on average than the Board's projected inflation rate.

Indeck's methodology for calculating operating charge revenue and the reimbursement for royalties was adopted in the Board's analysis. Royalties were calculated on the basis of a "floor" royalty provision of 80 percent of the average Alberta field price as projected in the Supply/Demand Report.

The Board's estimate of the variable gas sales revenue includes the operating charge revenue plus the reimbursements for royalties and all transporta-

tion charges. Total gas sales revenue (lump-sum payment plus variable gas sales revenue) amounts to $30.7 million in the Board's low oil price case at a 90 percent load factor. Indeck's low oil price case estimate of total gas sales revenue at a 100 percent load factor was $31.2 million.

The Board's control case and sensitivity analyses (see Tables 4-10 and 4-11) indicate that the Northstar-related sales to Indeck-Yerkes are unlikely to generate net benefits to Canada under a wide range of plausible assumptions. The control case under the low oil price scenario indicates that this export will generate a net loss to Canada of $2.5 million. Sensitivity tests performed at a higher discount rate and using 20 percent lower supply costs provide marginally positive results. All other sensitivity tests show that the Northstar-related sales to Indeck-Yerkes are not likely to generate net benefits to Canada.

Table 4-9

Indeck's Benefit-cost Summary
Indeck-Yerkes/Northstar
(millions of 1989$, discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Lump Sum & Operating	23.0	23.0
By-product Revenue	3.2	4.1
Reimbursement for Royalties	5.6	7.4
Reimbursement for Transportation	2.6	2.6
TransCanada Toll Revenue	11.7	11.7
Sub-total	46.1	48.7
Social Premium on Foreign Exchange	2.1	2.2
Total Gross Social Benefits	48.2	51.0
Costs		
Capital	10.8	10.8
Operating	6.6	6.6
Total Transportation Development	17.4	17.4
less Labour Externality	0.6	0.6
Total Social Cost of Transportation & Development	16.8	16.8
Total User Cost	17.0	27.6
Total Gross Social Costs	33.8	44.4
Total Net Social Benefits	14.4	6.5
Benefit/Cost Ratio	1.43	1.15

Table 4-10

NEB Benefit-cost Summary
Indeck-Yerkes/Northstar
(millions of 1989$ discounted at 8 persent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Lump-Sum Payment	16.4	16.4
Variable Gas Sales Revenue	14.3	15.9
By-product Revenue	6.9	10.3
TransCanada Toll Revenue	11.5	12.1
Total Benefits:	49.1	54.7
Costs		
Transportation Costs		
Capital	10.9	10.9
Operating	0.4	0.5
TIPC	40.2	55.7
Total Costs	51.6	67.0
Net Social Benefits	(2.5)	(12.3)
Benefit/Cost Ratio	0.95	0.82

Table 4-11

NEB Sensitivity Analyses of the
Northstar-related Sales to Indeck-Yerkes
(millions of 1989$)

	Low Oil Price Scenario	High Oil Price Scenario
Control Case (R/P Ratio = 12)	(2.5)	(12.3)
Different Discount Rate		
6% discount rate	(7.5)	(20.4)
10% discount rate	0.2	(7.7)
Load Factor Sensitivities		
85% Load Factor	(1.2)	(10.6)
95% Load Factor	(3.7)	(14.2)
Different Royalty		
10% Higher	(2.0)	(11.7)
10% Lower	(3.0)	(13.0)
No Facilities Credit	(5.2)	(15.0)
Different Supply Costs		
20% Higher	(6.6)	(17.5)
20% Lower	1.9	(7.1)
R/P Ratio=15	(6.1)	(18.7)
Different Demand Forecasts		
Exports @ 1.2 EJ/yr	(2.1)	(8.6)
Exports @ 1.8 EJ/yr	(4.4)	(14.4)

4.9 Disposition

In arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. Under this procedure the Board considers the EIA and complaints by Canadian gas-users taking into account current conditions in Canadian gas markets. In this regard the Board noted the absence of any complaints or opposition to the proposed export. Indeck submitted an EIA that demonstrated that the proposed export would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters, the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including the nature of the gas supply, transportation arrangements, gas sales contracts, and the expected net benefits to Canada associated with the proposed export.

The Board is not satisfied with the adequacy of Indeck's overall gas supply to meet the volume requirements of the licence sought. The Board's estimate of Saskatchewan reserves shows that supply exceeds requirements. However, the Board's estimate of Alberta reserves indicates that they are inadequate to meet requirements. The Board also notes that there are no backstopping arrangements nor any cross-dedication of Saskatchewan reserves that would allow Indeck to satisfy its total supply requirements for the Indeck Oswego and Indeck-Yerkes projects.

With respect to Indeck's evidence on markets and contractual arrangements, the Board considers that the cogeneration market offers potential for a high load factor operation and assurances that the gas contracted for will be taken. However, the Board is concerned that the Indeck Gas Sales and Purchase Agreements may not provide for sufficient flexibility to allow adjustments to reflect changing market conditions. The Board takes particular note of the use of a fixed escalator and the lack of any provision for price renegotiation over the term of the contracts.

The Board also assessed Indeck's benefit-cost analyses carried out for each of the Indeck Oswego, Indeck-Yerkes/BVI and Indeck-Yerkes/Northstar proposals. The Board has concluded that none of the three proposals would be likely to generate net benefits to Canada under the Board's control case. This finding was confirmed under a number of sensitivity tests.

In conclusion, the Board is not satisfied that the proposed exports are in the public interest. The Board was not satisfied with Indeck's evidence on gas supply. The Board is also concerned that certain of the terms and conditions of the Gas Sales and Purchase Agreements may not provide sufficient flexibility to allow adjustments to reflect changing market conditions. Finally, the Board is of the view that the applied-for exports are unlikely to generate net benefits to Canada. Therefore, the Board denies Indeck's application for an export licence.

ProGas Limited

5.1 Application Summary

By application dated 15 November 1988, ProGas requested the Board, pursuant to subsection 21(2) of the Act to amend natural gas export Licences No. GL-80 and GL-81 as follows:

(i) to transfer 10 226.3 10^6m^3 (361.0 Bcf) of term quantity from Licence No. GL-81 to GL-80;

(ii) to amend the term of Licence No. GL-80 to commence 1 November 1990 or the date of first deliveries for a period of 15 years;

(iii) to allow for the export of gas during the amended term of Licence No. GL-80 as follows:

- maximum daily quantity of 2 861.1 10^3m^3 (101 MMcf)
- maximum annual quantity of 1 044.3 10^6m^3 (36.9 Bcf)
- maximum term quantity of 15 665.3 10^6m^3 (553.0 Bcf); and

(iv) to reduce the maximum term quantity of Licence No. GL-81 by 10 226.3 10^6m^3 (361.0 Bcf).

In the alternative, ProGas requested:

a) a new licence with features identical to those requested for Licence No. GL-80 in paragraphs (i) to (iii) above;

b) revocation of Licence No. GL-80 upon issuance of the new licence referred to in paragraph (a); and

c) reduction of the maximum term quantity of Licence No. GL-81 by 10 226.3 10^6m^3 (361 Bcf)

Three U.S. buyers will purchase the gas from ProGas as follows:

- Tetco, an interstate pipeline company, will purchase up to 2 861.1 10^3m^3 per day (101.0 MMcfd) less the quantities sold to ProGas' other two buyers;
- Northeast Energy Associates, A Limited Partnership ("Northeast Energy") will purchase up to 1 018.6 10^3m^3 per day (36.0 MMcfd); and
- North Jersey Energy Associates, A Limited Partnership ("North Jersey Energy") will purchase up to 1 018.6 10^3m^3 per day (36.0 MMcfd).

Tetco's purchases will be utilized as part of its system supply requirements, while each of Northeast Energy and North Jersey Energy will use its gas to supply a cogeneration facility that it will build and operate in Bellingham, Massachusetts and Sayreville, New Jersey, respectively.

The gas to be exported by ProGas will be purchased in Alberta and shipped via NOVA and TransCanada to the international border at Niagara Falls, Ontario. From the border, the gas sold to ProGas' three customers would be transported by Tennessee to an interconnection with the pipeline system of CNG. CNG will transport the gas to a new pipeline segment jointly owned by National Fuel and Penneast Gas Services Company ("Penneast") connecting to the Transco and Tetco pipeline systems for delivery to Tetco and North Jersey Energy. The Northeast Energy supply will move through the Transco system to Algonquin Gas Transmission Company ("Algonquin") for delivery to Northeast Energy's facility in Bellingham, Massachusetts.

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably

foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an EIA; and other factors which the Board considers relevant in its determination of the public interest including, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements, markets, and net benefits to Canada.

5.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the ProGas export proposal.

5.3 Export Impact Assessment

ProGas analyzed three forecasts of natural gas supply and natural gas demand including exports. In the original EIA submitted with the application, ProGas estimated that the annual applied-for export volumes represented about 1.3 percent of the total forecast demand for Canadian gas. This estimate was not significantly altered by revisions to the EIA made to reflect more recent forecasts of gas supply and demand in Canada.

Based on its analysis, ProGas concluded that the ability of Canadian gas producers to satisfy domestic and export requirements would not be reduced as a result of its gas export proposal. ProGas also stated that this conclusion was not altered by assuming prior approval of a number of other applications submitted to the Board. While prior approval of other export applications would raise marginal supply costs, the resulting levels would still be generally lower than estimates of gas prices in forecasts analyzed by ProGas.

ProGas was of the view that Canadian gas prices will be established on the basis of total North American supply and demand. In this context ProGas does not expect the relatively small volumes of the proposed exports to affect future domestic gas prices.

Views of the Board

The Board agrees with the overall conclusion of ProGas that the applied-for export volumes should have little impact on Canadian production, consumption and prices of natural gas and that Canadian energy users would not have any difficulty in meeting their future energy requirements.

5.4 Gas Supply

5.4.1 Supply Contracts

ProGas' gas supply is contracted from approximately 180 producers under two purchase programs. The original purchase program (ProGas I) was completed in 1978 with a term of 25 years. This program comprises about 40 percent of ProGas' remaining reserves.

The second purchase program (ProGas II) was completed in 1981 with a term of 25 years. This program comprises about 60 percent of ProGas' remaining reserves.

5.4.2 Reserves

As shown in Table 5-1, the Board's estimate of reserves is approximately ten percent lower than that of ProGas. The difference can be attributed primarily to interpretation of pool size. Differences in parameters such as net pay, water saturation and porosity are also contributing factors. For the most part, the difference between ProGas' and the Board's estimates of reserves can be attributed to the cumulative effect of small differences in individual pools, rather than to a significant difference in estimates of reserves for any one pool.

Table 5-1

Comparison of Estimates of ProGas' Remaining Marketable Gas Reserves with the Applied-for Term Volume
$10^9 m^3$ (Tcf)

ProGas[1]	NEB[1]	Applied-for[2] Term Volume
96.2 (3.4)	86.2 (3.0)	15.7 (0.6)

1. as of December 31, 1987
2. ProGas total requirements are 84.9 $10^9 m^3$ (3.0 Tcf)

In its analysis of ProGas' gas supply, the Board recognized approximately 1 300 pools, all of which are in Alberta. These pools are located across most of the province and include all major producing zones. Most of the pools are concentrated in the Cretaceous zones of central and east-central Alberta. The Jurassic to Carboniferous zones contain about 50 pools located mainly in west-central Alberta. The Devonian pools are few in number and are located mostly in central Alberta. Almost 50 percent of ProGas' reserves are found in approximately 80 large pools each having initial established reserves in excess of 1 000 $10^6 m^3$ (35 Bcf).

In summary, the Board's estimate of reserves is slightly lower than ProGas' estimate, largely due to the cumulative effect of small differences in many pools.

5.4.3 Productive Capacity

Figure 5-1 compares the Board's and ProGas' projections of productive capacity with ProGas' requirements. ProGas estimated its requirements, including fuel and shrinkage, at a 90 percent load factor. For comparative purposes, the Board adjusted its productive capacity profile to reflect the assumed requirements, although it recognizes that ProGas' load factor may be higher than the assumed 90 percent level.

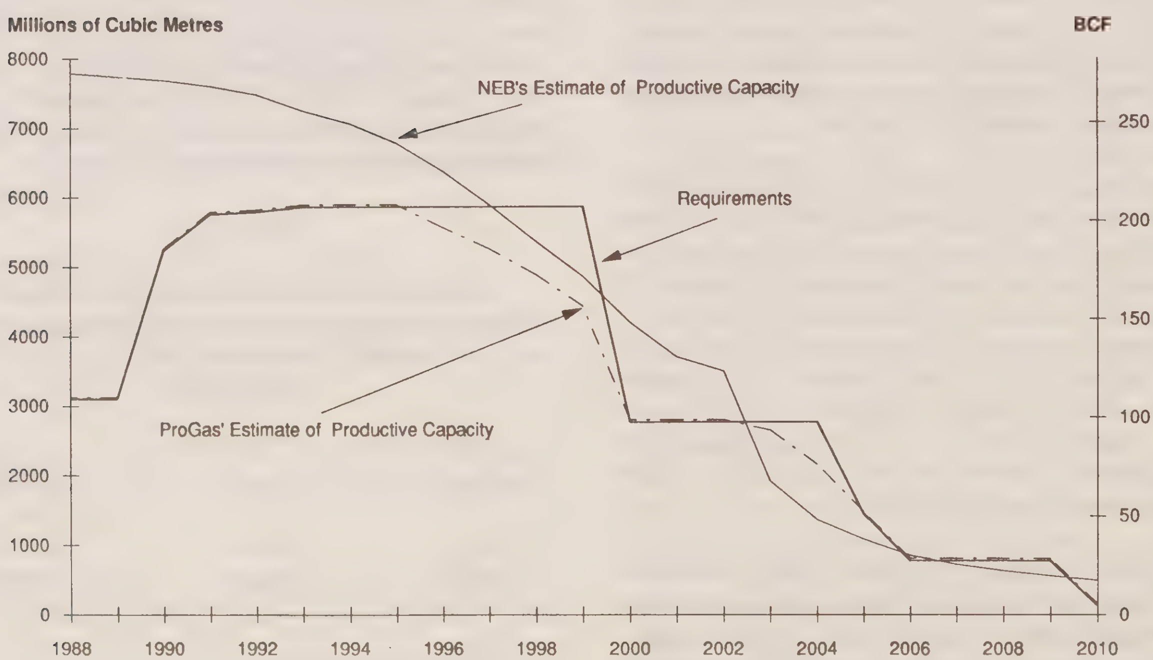
The Board's projection of productive capacity suggests potential deficiencies in supply from 1998-1999, and from 2003 through most of the remainder of the projection period. This compares to ProGas' projection, which indicates adequate supply throughout most of the proposed term, with the exception of the periods 1995-2000 and 2002-2005. ProGas indicated that it could increase the rate-of-take from its producers, develop additional reserves on its contracted lands or purchase additional supplies in order to avoid a shortfall in productive capacity.

Views Of The Board

The Board is of the view that ProGas will be able to meet its total requirements.

FIGURE 5-1

COMPARISON OF PROGAS' & NEB'S ESTIMATES
OF ANNUAL PRODUCTIVE CAPACITY



5.5 Energy Removal Authorization

ProGas stated that it has applied to the ERCB for minor amendments to its Alberta removal permit No. GR 86-71 which would provide for sufficient permit volumes to cover all of its sales requirements.

5.6 Market

ProGas' proposed gas exports of 2 861 10^3m^3 per day (101 MMcfd) would be for use by Northeast Energy, North Jersey Energy and Tetco. The volumes to be sold to Northeast Energy and North Jersey Energy were originally contracted to Tetco. However, due to market uncertainty experienced by Tetco as many of its larger LDC and industrial customers opted for transmission service only on Tetco's system, ProGas and Tetco agreed to seek alternative markets for the gas.

Northeast Energy and North Jersey Energy will each purchase 2 040 10^3m^3 per day (36 MMcfd) and Tetco has contracted for the remaining 821 10^3m^3 per day (29 MMcfd). In addition, in each contract year during the period 15 December through 31 March, if Northeast Energy or North Jersey Energy do not require the ProGas volumes for a period of 14 days or more, Tetco is obligated to purchase those volumes from ProGas provided that it is given 30 days prior notice of the availability of the gas.

5.6.1 Northeast Energy and North Jersey Energy Cogeneration Markets

Northeast Energy and North Jersey Energy both have Intercontinental Energy Corporation as their managing general partner. Both projects involve the construction of 300 MW combined cycle electrical generation facilities with associated steam production to be used in the production of carbon dioxide and various chemicals.

The Northeast Energy and North Jersey Energy combined cycle plants will be located in Bellingham, Massachusetts and Sayreville, New Jersey respectively. The cogeneration plants and associated carbon dioxide facilities are to be financed as a joint package and turnkey construction contracts for each plant have been signed with Westinghouse Electric Corporation. These contracts require that the facilities be constructed within a two-year period upon closing of financial arrangements.

Northeast Energy and North Jersey Energy have each contracted to sell the majority of their electrical production pursuant to long-term contracts ranging from 20 to 30 years with utilities within the New England Power Pool ("NEPOOL") and the Pennsylvania/ New Jersey/Maryland interconnected power pool, respectively. The contracts are must-run base load contracts that allow the electric utilities to refuse to purchase power for only up to 200 hours per year during the first ten years of the contract. After the initial 10-year period the North Jersey Energy contract permits the utility to refuse power for up to 400 hours per year.

ProGas demonstrated that the Northeast Energy and North Jersey Energy utility customers are experiencing increased peak day and total energy requirements. ProGas noted that these increases necessitated the must-run base load contracts.

ProGas stated that the Northeast Energy facility would supply steam to a plant that would manufacture carbon dioxide. The plant would be owned by Northeast Energy and located on its plant site, but would be leased on a long-term basis to National Energetics Corporation.

Steam produced at the North Jersey Energy facility will be sold to Hercules, Inc. and will be used to produce nitrocellulose and natrosol. Final contracts for the steam sales are near completion and the terms and conditions of the contracts would result in both cogeneration plants having QF status under the PURPA Regulations.

5.6.2 The Tetco Market

Tetco's market consists of a large number of LDCs in the northeast U.S. and two interstate pipeline companies, namely, Algonquin and CNG. In agreements dated 2 November 1986 and 3 November 1986, Tetco contracted with ProGas to purchase on a daily basis up to 1 416 10^3m^3 (50 MMcfd) and 1 445 10^3m^3 (51 MMcfd) respectively. However, as a result of a downturn in Tetco's requirements for system supply, a new agreement dated 14 January 1988 was executed which allowed ProGas to solicit direct sales to replace the volumes originally intended for Tetco. The sales to Northeast Energy and to North Jersey Energy occurred as a result of this arrangement.

ProGas submitted a forecast gas supply schedule for Tetco for the period 1989 through 2002 which

showed that deficiencies in Tetco's supply would occur during this period and would range from approximately 850 10^6m^3 (30 Bcf) per year in 1990 to 8500 10^6m^3 (300 Bcf) per year in 2002.

5.7 Contractual Arrangements

5.7.1 Transportation

The gas will be transported within Alberta by NOVA to TransCanada's facilities at Empress, Alberta. TransCanada will transport the gas to Niagara Falls, Ontario.

In the United States the gas will be transported by Tennessee on proposed looping of the Niagara spur to CNG's facilities in New York State. CNG will transport the gas to a new 40-mile segment of pipeline to be constructed and jointly owned by National Fuel and PennEast which will connect to the Transco and Tetco systems at Leidy, Pennsylvania.

Northeast Energy volumes will be received by Transco and delivered to Algonquin for delivery to the Bellingham cogeneration plant. North Jersey Energy volumes will be delivered by Transco to the Public Service Electric and Gas Company for transportation to the Sayreville, New Jersey plant.

ProGas stated that the U.S. transportation arrangements were in accordance with the Niagara Import Point Projects Settlement ("NIPPS") proceeding before the FERC and that the FERC had ruled that the transportation of gas to the Tetco system and the two cogeneration plants to be served by ProGas was discrete under the settlement. On 12 January 1989, the FERC had severed the project from the Northeast "open season" proceedings. ProGas testified that new applications and amendments to the applications necessary to implement this transportation have been filed with the FERC.

ProGas filed letters of intent from NOVA and TransCanada indicating their willingness to transport the gas contingent upon being able to modify or construct facilities as required.

5.7.2 Sales Contracts

ProGas filed copies of executed Gas Purchase Contracts dated 12 May 1988 with both Northeast Energy and North Jersey Energy, and a copy of a 30 September 1988 Amending Agreement to its 3 November 1986 Gas Sales Agreement with Tetco. The Amending Agreement provided for purchases of 2 861 10^3m^3 per day (101 MMcfd) from ProGas less the Northeast Energy and North Jersey Energy cogeneration purchases, and for backstopping of the cogeneration purchases during the period from 15 December through 31 March throughout the term of the contract or if the commencement of either or both of the cogeneration operations are delayed.

5.7.2.1 Northeast Energy and North Jersey Energy Sales Contracts

The Gas Purchase Contracts, both dated 12 May 1988, between ProGas and each of Northeast Energy and North Jersey Energy are similar except that the price escalation clauses vary. Each contract provides for sales of 1 016 10^3m^3 per day (35.9 MMcfd) for a period of 15 years upon commencement of firm deliveries. As well, the contracts include a condition whereby ProGas would sell additional daily quantities of gas to either Northeast Energy or North Jersey Energy provided that supply and transportation capacity was available.

The 15-year terms of the two contracts may be extended for two successive five-year periods if the parties agree.

The cogeneration contracts include provisions whereby ProGas, on an ongoing basis, must verify that it has sufficient reserves and deliverability to meet its obligations under the contract. Should reserves and deliverability decline, the buyers could restrict ProGas from entering into new contracts or making spot sales to others. Failure to maintain adequate reserves or deliverability would permit the buyers to seek alternate supplies and requires ProGas to cooperate in arranging the necessary capacity for transportation of those alternate supplies on the NOVA and TransCanada systems.

The cogeneration contracts include a 75 percent minimum annual purchase obligation and a provision which provides for *pro rata* purchases with other U.S. sales to the cogeneration facilities when those purchases exceed a 75 percent load factor. If the buyers purchase less than 75 percent of the contract quantity on an annualized basis, then the shortfall is added to the next year's minimum purchase obligation.

The cogeneration contracts set an export price composed of a demand charge and a commodity charge. The demand charge is made up of the NOVA and TransCanada demand tolls plus ProGas' cost of service as approved by the Alberta Petroleum Marketing Commission ("APMC").

The commodity charge for both the Northeast Energy and North Jersey Energy contracts is $U.S. 1.9365 /MMBtu effective 1 January 1990.

The Northeast Energy export price will be adjusted each 1 January thereafter based on changes in Northeast Energy's power sales rates for both fixed rate sales and avoided cost sales to utilities on a weighted basis.

The North Jersey Energy contract has an export price that is adjusted annually, with the adjustment reflecting changes in the cost of gas to New Jersey electric utilities.

ProGas forecasted that the export price on 1 January 1990 would be $U.S. 2.68/Mcf (including a demand charge of $U.S. 0.74/Mcf).

The Northeast Energy and North Jersey Energy contracts include provisions that allow either the buyer or seller to require renegotiation of the pricing terms and conditions annually.

5.7.2.2 The Tetco Sales Contract

The 3 November 1986 ProGas/Tetco Gas Sales Agreement, as amended, provides for sales of 2 861 10^3m^3 per day (101 MMcfd) less the Northeast Energy and North Jersey Energy daily contract quantities (totalling 2 039 10^3m^3 per day (72 MMcfd)) during the period to 31 October 2002.

During the period 15 December through 31 March of any contract year, the daily contract quantities of gas that are not purchased by Northeast Energy and North Jersey Energy and that are available to Tetco for a period not less than two weeks, will be added to the Tetco/ProGas daily contract quantity.

Tetco has agreed to purchase gas from ProGas on a *pro rata* basis with its other U.S. purchases pursuant to firm contracts having terms in excess of three years.

Make-up is permitted in the following year and, if Tetco does not make those purchases up in that year, it must make 12 monthly interest payments to ProGas based on the commodity charge that would have been payable at an interest rate of prime plus one percent.

The agreement includes a provision whereby ProGas will seek the required authorization to provide for a one-year extension of the agreement to permit Tetco the opportunity to make up remaining deficiencies at the end of the contract term. If the authorization is not obtained, Tetco's obligation to make interest payments is terminated.

The amended agreement includes a Special Marketing Agreement whereby the parties agree that from time to time, ProGas may have to market gas to Tetco or its marketing affiliate at special prices so as to remain competitive. In any year, once the buyer has purchased the minimum annual quantity, special purchases would reduce the previous year's deficiency quantity.

The contract includes a provision whereby Tetco can request excess gas above the daily contract quantity and ProGas agrees it will deliver provided it has the necessary supply and transportation capacity available. Excess gas quantities delivered pursuant to special marketing arrangements cannot be considered for make-up purposes.

ProGas' export price for sales to Tetco is made up of a demand charge and a commodity charge. The demand charge is the sum of the NOVA and TransCanada tolls plus the ProGas charges for its services as approved by the APMC less the portion of the demand charge applicable to special marketing agreements sales and the amounts, if any, by which the commodity charge for special marketing agreements exceeded the regular commodity charges.

The regular commodity charge for ProGas sales to Tetco is the Tetco commodity charge in its CD-1 Rate Schedule as approved by the FERC, reduced by the commodity charge component of Tetco's U.S. transportation charges.

ProGas and Tetco agreed to adjust the demand and commodity charges to reflect changes in competitive conditions in Tetco's market.

Views of the Board

The pricing conditions in the Northeast Energy and North Jersey Energy Gas Purchase Contracts

and in the Tetco Gas Sales Agreement provide that the U.S. buyers shall pay a monthly demand charge consisting of the sum of:

- the monthly demand toll per Mcf as billed by NOVA for firm transportation service within Alberta;
- the monthly demand toll per Mcf on TransCanada's system for firm transportation service; and
- the monthly demand toll per Mcf as billed by ProGas for its monthly services.

In addition the commodity price under the contracts and agreement will recover variable transportation costs.

The Board is satisfied that the demand charge component of the export price will act to ensure that associated transportation fixed costs within Canada will be recovered under the contracts and agreement.

The Northeast Energy and North Jersey Energy Gas Purchase Contracts allow for the adjustment of the base commodity price on an annual basis. The Northeast Energy price will be adjusted to reflect changes in Northeast Energy's facility power sales rates expressed as ratios of fixed rate sales to total Bellingham sales.

The North Jersey Energy contract includes a pricing provision that ties the annual adjustment to changes in the cost of gas sold to New Jersey utilities.

Both contracts include annual renegotiation rights of the pricing provision for either party when due notice is provided.

The Board considers that the annual pricing adjustment provision in each of the cogeneration contracts will allow contract prices to remain flexible and market-responsive. The annual renegotiation condition in the contracts provide assurance that in future years, should the price adjustment condition in the contracts not allow the price to escalate at competitive rates with other similar type sales, then the seller can seek relief.

The Tetco Gas Sales Agreement permits changes in the export price to reflect changes in prices for alternate gas supplies available to Tetco. In addition, either party may require renegotiation of the pricing provision if changes occur in market-responsive prices in Tetco's gas purchase contracts for system supply or if Tetco makes a new Purchase Gas Adjustment ("PGA") filing to the FERC.

The Board is satisfied that the ProGas/Tetco pricing conditions offer adequate flexibility to reflect changing market conditions.

The Northeast Energy and North Jersey Energy Gas Purchase Contracts include minimum annual take provisions equal to 75 percent of the annual contract quantity as well as *pro rata* take provisions tied to the average purchases by the cogeneration plants from other suppliers of gas.

In the event that either or both Northeast Energy and North Jersey Energy were unable to meet take obligations during the winter period, then Tetco is obligated, subject to certain conditions, to take the gas.

Finally, the two cogeneration plants have "must run" contracts under which the purchasing utilities can refuse to purchase power for a maximum of 200 hours per year, resulting in potentially high load factor operations.

The Board is satisfied that the contracts provide reasonable assurance of take.

The Tetco Gas Sales Agreement includes a *pro rata* take provision requiring that Tetco take gas in proportion to the ratio of its purchases from U.S. suppliers to the volume available from Tetco's U.S. pipeline and field suppliers, under contracts having more than a primary term of three years. As well, the agreement includes interest penalties on volumes not taken above a minimum annual quantity.

The Board is of the view that the *pro rata* take provisions and the interest penalties will act to ensure that a reasonable level of sales will occur under this agreement.

ProGas filed findings of producer support for the three proposed export sales in support of its application.

5.8 Benefit-cost Analysis

Table 5-2 shows the results of the benefit-cost analysis that ProGas submitted in its application. This study indicated that the applied-for exports

would yield total net benefits to Canada of approximately $141 million, (1988$) using an 8 percent discount rate.

The export price for the Tetco sale is tied directly to the price of U.S. natural gas. The commodity charge was estimated by ProGas to be $2.53/GJ ($2.71/MMBtu) in 1990 and was forecasted to grow at a rate based on the Niagara price index. This index is derived from a forecast of Niagara Falls export prices that was provided by TransCanada. After adjustments for transportation charges were made, export prices at Niagara Falls were forecasted to be $ 3.81/GJ ($4.09/MMBtu) (1988$) in the year 1990 and to increase to $ 4.90/GJ ($5.26/MMBtu) (1988$) by 2005.

The export price for the Northeast Energy and North Jersey Energy sales depends upon four factors:

- the base price in both contracts which is 1.94/MMBtu in 1990;
- one-half of the Northeast Energy sales price which escalates according to a contractually-fixed annual price escalator;
- the remaining fifty percent of the Northeast Energy sales price which is tied to the change in avoided costs of the cogeneration facility's customers; and
- the North Jersey Energy contract's escalation index which ties the rate of growth in the base price to the rate of growth of delivered gas prices into New Jersey.

ProGas forecasted that, after adjustments for demand charges were made, the export price at Niagara Falls would be $ 3.18/GJ ($3.41/MMBtu) (1988$) in the year 1990 and $4.73/GJ ($5.07/MMBtu) (1988$) by 2005.

The load factors assumed by ProGas are 70 percent for the Tetco sale and 90 percent for the cogeneration plant sales. By-product revenue per unit of gas delivered to NOVA was assumed to equal 12 percent of the world oil price on a heat equivalent basis.

ProGas estimated the net present value of incremental capital expenditures on TransCanada and NOVA to be $193 million, (1988$) and TransCanada incremental operating costs to be $0.13/GJ ($0.14/MMBtu). NOVA operating costs were estimated to be $0.0068/GJ ($0.073/MMBtu). Fuel gas costs were included in field production costs. Total transportation costs over the project's life were projected to be $227 million in present value terms (1988) ProGas submitted that field production costs would average $0.72/GJ ($0.77/MMBtu).

ProGas estimated the user cost associated with the forecasted export volumes using supply cost estimates and domestic natural gas demand forecasts outlined in the low and the high oil price scenarios in the report entitled *National Energy Board Canadian Energy Supply and Demand 1985-2005* dated October 1986 ("1986 Supply/Demand Report"). In forecasting total gas production in absence of the applied-for export, ProGas used the lesser of a February 1988 IPAC forecast or currently licensed export volumes. Because licensed export volumes drop off sharply after 1995, ProGas' methodology results in a forecast in which exports drop below 8.5 10^9m^3 per year (300 Bcf per year) after 1994.

ProGas maintained that its methodology was appropriate because it focused on the user cost of export authorizations over and above currently licensed levels.

In summary, ProGas argued that its applied-for exports would provide net benefits to Canada.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

As explained in Appendix I of these Reasons, the Board used aggregate industry data to calculate by-product revenues and used a forecast of exports rather than simply currently licensed exports to calculate the TIPC (including user costs).

The Board prepared its own benefit-cost analysis of ProGas' application (See Table 5-3). Since the average price received by ProGas is the same regardless of whether one or both of the cogeneration facilities reach commercial operation, the Board is of the view that the proposed sales to the cogeneration projects should be treated as a package. The Tetco sale is evaluated independently.

The Board adopted ProGas' forecasted load factors for each of the contracts. The Board does not, however, share ProGas' outlook of a 1 November 1990 "commercial date" for the cogeneration facilities. Based on (Exhibit C-5-13, ProGas' response to NEB Information Request No. 2), the Board finds a "commercial date" of 1 January 1992 to be more reasonable. This assumption alters the volume profiles of the contracts.

The Board's analysis indicates that the proposed Tetco, Northeast Energy and North Jersey Energy sales will likely generate net benefits to Canada at the low world oil price scenario. As shown in Table 5-4, the Board's sensitivity analyses indicate that the contracts should generate net benefits under a wide range of plausible assumptions in the low oil price scenario.

Table 5-2

ProGas' Benefit-cost Analysis of its Proposed Export
(millions of 1988$, discounted at 8 percent)

Benefits:	
Tetco Gas Exports	248.83
Northeast Energy and North Jersey Energy Gas Exports	683.88
By-product Revenue	124.59
Total	1,057.30
Costs:	
User Cost	488.05
Production Costs	201.28
Transportation Costs	226.67
Total	916.00
Net Social Benefits:	141.30
Benefit/cost Ratio:	1.15

Table 5-3

NEB Benefit-cost Analysis Of Progas' Export Proposal
(millions of 1988 Canadian dollars at an 8 percent discount rate)

	TETCO		Northeast Energy and North Jersey Energy	
	Low Oil Price Scenario	High Oil Price Scenario	Low Oil Price Scenario	High Oil Price Scenario
Benefits				
Gas Export Revenue	282.36	341.70	563.04	646.32
By-Product Revenue	32.66	49.00	69.03	103.53
Total	315.02	390.70	632.07	749.85
Costs				
Total Incremental Production Costs	208.56	288.10	485.03	675.93
Transportation Costs				
Operating Costs	2.32	2.40	4.96	5.18
Capital Costs	51.62	51.39	119.77	119.22
Total	262.51	341.89	609.76	800.33
Net Social Benefits	52.51	48.81	22.32	-50.48
Benefit/Cost Ratio	1.20	1.14	1.04	0.94

Table 5-4

NEB Sensitivity Analyses of Progas' Export Proposal
(Net Benefits in millions of $1988 Canadian Dollars)

	TETCO		Northeast Energy and North Jersey Energy	
	Low Oil Price Scenario	**High Oil Price Scenario**	**Low Oil Price Scenario**	**High Oil Price Scenario**
Control Case	52.51	48.81	22.32	-50.48
Different Discount Rate				
6% Discount Rate	36.43	32.21	6.25	-95.68
10% Discount Rate	52.10	52.61	19.43	-38.46
Load Factor Sensitivities				
High Load Factor*	57.94	56.00	21.63	-55.02
Low Load Factor**	47.28	41.73	22.89	-45.46
Different Gas Prices				
10% Higher	77.87	80.02	n.a	n.a
10% Lower	27.14	17.59	n.a	n.a
No Facilities Credit	39.98	36.27	-6.76	-79.56
Different Supply Costs				
20% Higher	31.22	21.91	-26.99	-113.78
20% Lower	75.41	75.61	76.01	12.83
R/P Ratio = 15	34.11	11.61	-29.78	-120.08
Different Demand Forecasts for TIPC Calculations				
Exports at 1.2 EJ/yr.	55.08	68.21	31.64	-0.68
Exports at 1.8 EJ/yr.	42.31	38.31	-1.39	-77.07

* assumes the following load factors: Tetco 75%,Northeast 95%, NorthJersey 95%
** assumes the following load factors: Tetco 65%,Northeast 85%, NorthJersey 85%

5.9 Disposition

The Board has decided to issue a new gas export licence to ProGas. Governor in Council approval of the new licence is required before this decision comes into effect. Appendix II contains the terms and conditions of the proposed licence including a condition that states that the term of the licence shall commence on the date that Governor in Council approval is received and shall end on 31 October 1991, unless exports commence under the licence on or before 31 October 1991, in which case the term will end on 31 October 2005. The Board notes that ProGas' application sought approval for amendments to two existing gas export Licences No. GL-80 and GL-81 or in the alternative for a new licence. Insofar as the Board has decided to issue a new licence to ProGas, the Board will also amend Licence No. GL-80 to reduce the maximum term quantity in that licence by 10 226.3 10^6m^3 (361.0 Bcf). In addition, having reviewed the matter with ProGas during the public hearing and having received Progas' consent, the Board will, upon the issuance of ProGas' new licence, issue an order revoking Licence No. GL-81.

In arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia*, whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements.

Under this procedure the Board considers the EIA and complaints by Canadian gas-users taking into account current conditions in Canadian gas markets. In this regard the Board noted the absence of any complaints or opposition to the proposed export. ProGas submitted an EIA which demonstrated that the proposed export would have little or no impact on total production, prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, transportation arrangements and the expected net benefits to Canada associated with the proposed export.

In its assessment of gas supply the Board reviewed ProGas' estimates of reserves and productive capacity and compared those estimates with its own. The Board's projection of ProGas' productive capacity suggested minor potential deficiencies in the latter years in the project. However, the Board was satisfied with the measures proposed by ProGas to avoid such shortfalls. The Board is therefore satisfied that ProGas has sufficient supply to meet its total requirements.

The Board believes that ProGas' proposed system sale to Tetco and the sales to Northeast Energy and North Jersey Energy will occur at high load factors. The Board is also satisfied that the contractual arrangements will allow for flexibility in order to reflect changing market conditions over time.

The Board's review of the net benefits to Canada expected to result from ProGas' proposed export showed that the project was likely to generate net benefits to Canada.

Chapter 6

Shell Canada Limited

6.1 Application Summary

By application dated 21 November 1988, as amended, Shell requested the Board, pursuant to subsection 21(2) of the Act, to amend natural gas export Licence No. GL-100 as follows:

(i) to extend the term of the licence from 31 October 2004 to 31 August 2011;

(ii) to increase the maximum daily and annual quantities for export at Niagara Falls, Ontario during the period 1 June 1990 to 31 March 1999 by 450.0 10^3m^3 (15.9 MMcf) and 145.0 10^6m^3 (5.1 Bcf), respectively;

(iii) during the period 1 April 1999 to 31 August 2011, to provide for maximum daily and annual exports of 450.0 10^3m^3 (15.9 MMcf) and 145.0 10^6m^3 (5.1 Bcf), respectively; and

(iv) to increase the term quantity by 2 755 10^6m^3 (97.2 Bcf).

The gas proposed for export would be produced from reserves that Shell holds in a number of fields in Alberta. The gas would be transported by NOVA and TransCanada to Niagara Falls, Ontario. At the international border, the gas would be sold to Salmon Resources Ltd. ("Salmon") for shipment on the Tennessee, CNG and Niagara Mohawk systems for ultimate delivery to Cogen Energy Technology Inc. ("CETI").

CETI intends to construct and operate a cogeneration plant at Castleton-on-Hudson, New York. The electricity would be sold to Niagara Mohawk and steam would be purchased by Fort Orange Paper Company ("Fort Orange Paper") for its paper mill operating at Castleton-on-Hudson.

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an EIA; and other factors which the Board considers relevant in its determination of the public interest including, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements, markets, and net benefits to Canada.

6.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Shell export proposal.

6.3 Export Impact Assessment

Shell concluded that the ability of Canadian gas producers to satisfy domestic and export requirements would not be reduced as a result of its gas export proposal. According to Shell, the proposed exports represent about 0.13 percent of Canada's remaining established reserves, excluding frontier reserves. On an annual basis, Shell estimated its proposed exports to be 0.29 percent of current annual consumption of natural gas in Canada. In this context Shell did not expect the relatively small volumes of the proposed exports to affect future domestic gas prices.

Views of the Board

The Board agrees with Shell's overall conclusion that the applied-for export volumes should have little impact on Canadian production, consumption and prices of natural gas and that Canadian energy users would not have any difficulty in meeting their future energy requirements.

6.4 Gas Supply

6.4.1 Supply Contracts

Since Shell intends to supply the proposed export with gas from its own pools, no gas supply contracts were required.

6.4.2 Reserves

Table 6-1 shows that the Board's estimate of Shell's remaining marketable gas reserves is approximately 20 percent lower than that of Shell, however, the Board's estimate exceeds the applied-for volume by 51 percent. The interpretation of pool area and net pay are the major reasons for the differences in estimates of reserves.

In its analysis of Shell's gas supply, the Board recognized 13 gas pools within seven fields in Alberta. The pools are in the Triassic, Mississippian and Devonian zones. Over 90 percent of Shell's reserves are concentrated in five large pools, each with initial established reserves in excess of 1 000 10^6m^3 (35 Bcf).

For the Hamburg Slave Point pool, Shell's estimate of average pay is approximately 70 percent higher than the Board's estimate. Shell assumed uniform thickness throughout the pool area whereas the Board used a more conventional contoured net pay map.

Table 6-1

Comparison of Estimates of Shell's Remaining Marketable Gas Reserves with the Applied-for Term Volume
10^6m^3 (Bcf)

Shell[1]	NEB[2]	Applied-for Term Volume
25 728 (908)	19 859 (701)	13 155 (464)

1. as of January, 1988
2. as of December, 1988

The Board's estimate of reserves for the Clearwater Turner Valley pool is smaller than Shell's estimate due primarily to differences in net pay and Shell's inclusion of a large probable area.

Shell adopted ERCB estimates of reserves for three Turner Valley pools in the Panther River field. The Board's estimate of reserves is 265 10^6m^3 (9 Bcf) less than that of Shell due to a slightly lower estimate of porosity.

In the Progress and Pouce Coupe South fields, the Board's estimates of reserves for the seven pools are lower than those of Shell. The primary reason for these differences is pool area. In four of the pools, Shell assigned a productive area of 259 hectares for the single-well gas pools. The Board assigns a smaller area (150 to 200 hectares) to single-well gas pools unless geological or other evidence supports using a larger area. The Board's estimates of area averaged 68 percent of Shell's estimates for these pools and resulted in a 401 10^6m^3 (14 Bcf) difference in estimates of reserves.

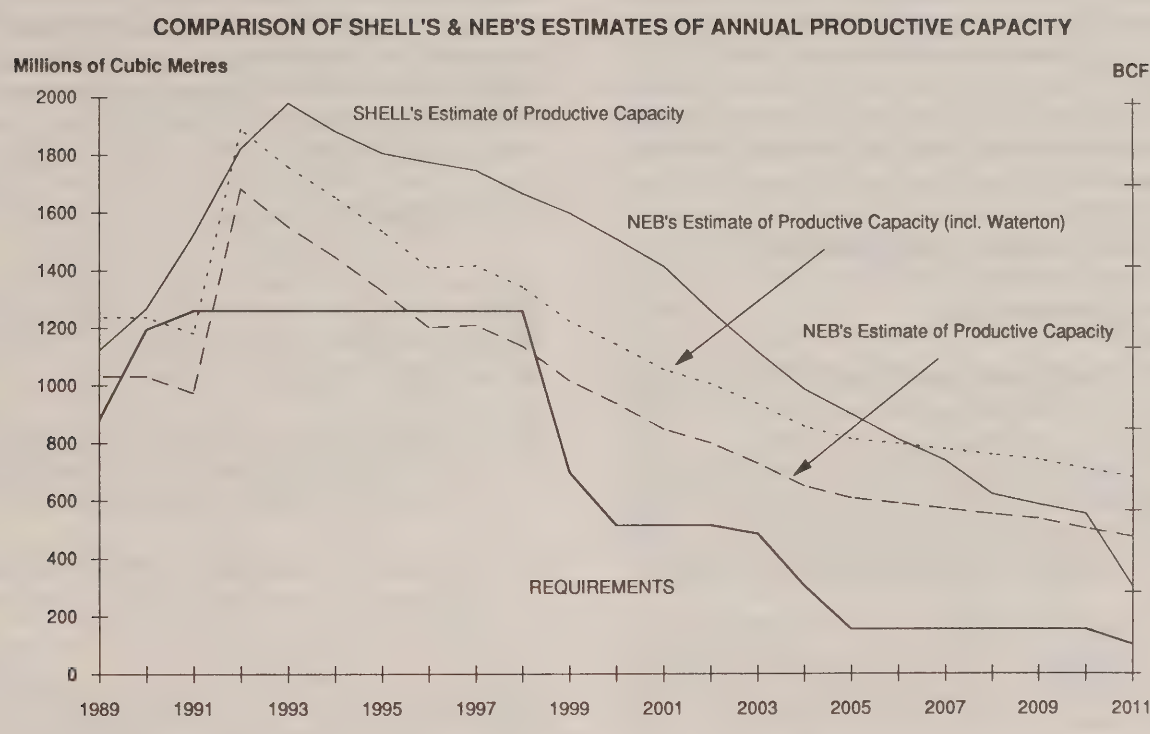
In summary, the Board's estimate of reserves is considerably lower than that submitted by Shell. This is due to different interpretations of several pool parameters, with net pay and pool area being most significant. However, the Board's estimate of Shell's reserves exceeds the applied-for volumes.

6.4.3 Productive Capacity

Figure 6-1 compares the Board's and Shell's projections of productive capacity with the applied-for volumes including fuel and shrinkage.

Shell's projection of its productive capacity indicates that it can meet its total requirements (including fuel and shrinkage) throughout the term. The Board's projection of Shell's productive capacity suggests that minor deficiencies may occur during 1990 and 1991 and then again from 1996 to 1998. This difference in outlook is attributable primarily to the difference in estimates of reserves. However, for deliverability purposes, Shell can take up to 566 10^3m^3 per day (20 MMcfd) from its Waterton field under an agreement with Alberta & Southern Gas Co. Ltd.("Alberta and Southern").

FIGURE 6-1



Views Of The Board

Considering the availability of the additional gas from the Waterton field, the Board is of the view that Shell would be able to meet its total requirements throughout the term.

6.5 Energy Removal Authorizations

Shell holds Alberta removal permit No. GR 86-46A. An application to add the Caroline field to the list of pools named in the removal permit and to increase the total authorized volume to 13 490 10^6m^3 (476 Bcf) is currently before the ERCB.

6.6 Market

The proposed export would be used as fuel at a gas-fired combined cycle cogeneration plant that CETI plans to construct at Castleton-on-Hudson in New York State. CETI was formed in 1986 to identify, develop and operate cogeneration projects and is affiliated with Hydro Development Group Inc. which currently operates 15 small hydro-electric plants in New York, Pennsylvania and New England.

The CETI plant has been certified as a QF and will have an electrical generating capacity of approximately 60 MW. It will be a base load electrical generator and will be connected to the Niagara Mohawk transmission system. Niagara Mohawk, (which has some 1.4 million electric customers in New York State) and CETI have signed a 40-year contract under which Niagara Mohawk will purchase 100 percent of CETI's electrical output. The plant will also generate 29 million pounds of steam on an annual basis which will be sold to Fort Orange Paper under a 20-year steam supply agreement.

Construction of the cogeneration plant was expected to commence in June or July 1989. Shell testified that although financing of the proposed cogeneration plant is not dependent on securing an export licence, a firm service transportation contract with TransCanada or a fuel plan, there must be evidence that action has been taken to secure

them. Shell anticipated that the plant would be completed, tested and running by October or November 1990. However, gas might be required as early as June 1990 for testing purposes.

Shell stated that the cogeneration plant would operate at a 93 percent load factor.

With respect to the U.S. import authorization, Shell stated that Salmon, a subsidiary of Shell, would be filing an application.

6.7 Contractual Arrangements

6.7.1 Transportation

The gas to be exported would be transported within Alberta by NOVA to Empress and from that point by TransCanada to Niagara Falls, Ontario. In the United States, the gas would move through the Tennessee and CNG systems to a proposed interconnection with the Niagara Mohawk system which would be extended to connect with the CETI plant.

With respect to shipments on the NOVA system, Shell has signed Service Agreements for the proposed export quantities. Shell has also signed a transportation Precedent Agreement with TransCanada.

In the United States, where CETI is responsible for transportation arrangements, a letter precedent agreement has been signed with CNG covering transportation from the international boundary to Niagara Mohawk's facilities at Brookview, New York. The precedent agreement provides that the gas would be carried at CNG's option from Niagara Falls either:

- to Brookview via the CNG system; or
- to a proposed new interconnection between the Tennessee and CNG systems at Marilla, New York via the Niagara Spur; and then from Marilla to Brookview via the CNG system.

CNG has chosen the second option and a precedent agreement has been signed with Tennessee for transportation of CETI's gas on the Niagara Spur to Marilla.

Some additional facilities will also be required on both the Tennessee and CNG pipeline systems. Applications have been filed with the FERC and Shell did not anticipate any delays in the granting of regulatory approvals.

Shell also filed a signed letter precedent agreement between CETI and Niagara Mohawk with respect to the transportation of CETI's gas by Niagara Mohawk from the CNG system to the CETI plant via a 2.7-mile pipeline that would be constructed by Niagara Mohawk.

6.7.2 Sales Contracts

The gas to be exported would be sold by Shell to Salmon which, in turn, would re-sell the gas to CETI. In support of its application, Shell filed the following executed agreements:

(i) an executed letter Precedent Agreement dated 5 May 1988 between Shell and Salmon as amended 27 February 1989; and

(ii) an executed Gas Sale and Purchase Contract between Salmon and CETI dated 13 July 1989.

Because of the uncertainty as to when the cogeneration facility would commence operations and the date on which firm transportation would become available, the Gas Sale and Purchase Contract has been structured to accommodate potential delays in the start-up date. The obligations to take gas are best described by breaking down the term into its three constituent periods, namely, the testing period, the pre-firm transportation period and the firm transportation period.

Testing period

During the testing period, which would not begin sooner than 1 June 1990, and until commercial operations commence, Salmon is obligated to deliver U.S. gas or, to the extent that interruptible transportation in Canada is available, Canadian gas. If Canadian gas is delivered, Shell is to supply up to 450 10^3m^3 per day (15.9 MMcfd) on a best-efforts basis.

Pre-firm transportation period

This period extends from the date on which commercial operations begin to the date on which firm transportation service in Canada and the United States becomes available. During this period,

Salmon has contracted to purchase either U.S. gas and/or Canadian gas. Shell testified that if and when U.S. gas deliveries start, they would continue to flow until at least 1 November 1991.

If Salmon were to choose to satisfy its obligation with Canadian gas, then Shell, at the request of Salmon, could deliver the MDQ (up to 397 10^3m^3 per day (14 MMcfd)) on an interruptible basis. Furthermore, Shell would deliver additional gas in excess of the MDQ, on a best-efforts basis, up to a maximum of 450 10^3m^3 per day (15.9 MMcfd), this being the Aggregate Daily Quantity ("ADQ").

If Salmon were to choose to supply CETI with U.S. gas, and there were times when these supplies were not available, interruptible Canadian gas would, if available, be used. Although U.S. gas supply could continue to fuel the cogeneration facility beyond 1 November 1991, Shell expected Canadian gas to flow on this date on a firm basis.

Firm transportation period

Once the plant is operating and firm transportation service is available, Salmon is obligated to purchase Canadian gas from Shell and to supply it to CETI subject to any remaining obligation Salmon might have to deliver U.S. gas. From this point in time, Salmon must, on request, deliver up to the MDQ. Shell must also, on a best-efforts basis, deliver Canadian gas up to the ADQ.

Salmon/CETI pricing structure

The Salmon/CETI Gas Sale and Purchase Contract provides for a two-part pricing mechanism consisting of a demand charge and a commodity charge. The demand charge is structured to ensure recovery of fixed costs of transportation in Canada.

The commodity price of the gas would increase based on Niagara Mohawk's avoided costs which would be calculated on a quarterly basis as expressed by a weighted average floating tariff ("WAFT"). The price would be determined as follows:

(i) the contract price is fixed at $U.S. 2.76/GJ ($U.S. 2.97/MMBtu) until the WAFT exceeds a threshold of 6 cents/ Kwh.

(ii) once this threshold is passed, the price is linked to but would grow at less than the growth in the WAFT.

(iii) after the thirteenth contract year, the price would increase at the same rate of growth experienced by the WAFT.

In the first years of the contract, until the WAFT reaches a threshold level of $U.S. 0.06/Kwh, the Niagara Falls export price is fixed at $U.S. 2.97/ MMBtu (1988$). In the following years, the export price is indexed to a growth rate less than that of the avoided costs. After the thirteenth contract year, the export price increases at a rate equal to the growth in Niagara Mohawk's avoided costs. A surcharge, which remains constant at $U.S. 0.07/ MMBtu (1988$) until the thirteenth year of the contract, is added to the base price after the threshold level has been passed, and increases to $U.S. 1.50/MMBtu (1988$) by the end of the contract term.

Shell's projection of Niagara Mohawk's long-run avoided costs is based on the 1989 forecast published by the NYSPSC. Shell made adjustments to create two projections of Niagara Mohawk's avoided costs which would reflect the high and low oil price scenarios from the Supply/Demand Report. Both of these forecasts projected prices to increase rapidly over the period to 1996, moderating thereafter to approximate the assumed 4.5 percent rate of inflation.

In respect of the gas price, Shell testified that in March, 1989, the border price would have been $U.S. 2.265/GJ ($U.S. 2.44/MMBtu). Once U.S. transportation costs are included, the plant gate price would have been $U.S. 2.66/GJ ($U.S. 2.86/ MMBtu).

The Gas Purchase and Sale Contract does not include a renegotiation clause.

Views of the Board

The Board is satisfied that the Shell/Salmon Precedent Agreement and the Salmon/CETI Gas Sale and Purchase Contract provide for the recovery of all fixed costs of transportation in Canada through the inclusion of a demand charge component in the pricing provision.

The Board's analysis of the pricing provisions of the Gas Sale and Purchase Contract indicates that, in real terms, the border price would likely decrease in the early years of the project and would only increase moderately until 2005. After

2005, the price would increase more rapidly because of the inclusion of significantly larger surcharges. Shell's projections of gas prices match the Board's.

Given these results, the Board is concerned that the contractual pricing provisions may not allow adequate flexibility to ensure price competitiveness, particularly in the early years of the contract when the price is essentially fixed and decreases in real terms. Even after the 6 cent/Kwh threshold is reached, the price is precluded from increasing at the same rate as the WAFT until after the thirteenth year. The Board also considers that, although Niagara Mohawk's avoided cost is a reasonable basis for gas prices competing in the electric generation market, the preponderance of No. 6 fuel oil and coal in its make-up reduces the likelihood that prices for gas sold to this market would be able to reach their opportunity value. Finally, the Board is also concerned that the Precedent Agreement and the Gas Sale and Purchase Contract contain no renegotiation clause which would allow flexibility and give the parties an opportunity to reconsider their positions in the event that future developments resulted in gas prices that did not accurately reflect market conditions.

With respect to assurance of take, the Board notes that Salmon would be the exclusive supplier of all fuel for the plant. Once firm transportation arrangements were finalized it is expected that Shell's gas would be the primary fuel for the plant subject to Salmon's obligations, if any, to deliver U.S. gas.

In the Board's view the CETI plant would likely operate at a high load factor, and given the pricing provisions of the Shell/Salmon/CETI contracts, the Shell supply would be taken. In addition, the Board considers that the demand charge, payable regardless of throughput levels, would also act as an incentive for the buyer to purchase Shell's gas.

Insofar as Shell holds the working interest in all of the gas reserves proposed to be exported to CETI, the question of producer support is not an issue.

6.8 Benefit-cost Analysis

Shell submitted the benefit-cost analysis summarized in Table 6-2. That analysis indicates net benefits to Canada for both the high and low world oil price scenarios, with all project benefits and costs discounted at 8 percent real.

Shell's high and low oil price scenarios are based on the energy prices included in the Supply/Demand Report. The gas export prices are linked to Shell's estimates of the avoided costs of Niagara Mohawk as expressed by the WAFT.

Shell's projected export price in 1988 dollars decreases, in real terms, in the early years, increases very modestly until 2005 and then grows more rapidly in the remaining years.

Shell assumed a load factor of 93 percent for each year of the contract.

Shell estimated by-product revenues based on the by-product content of its reserves which included some fields rich in gas liquids and sulphur. Consequently, Shell projected that by-product revenues would increase the gas sales revenues by 41 percent in the low oil price scenario and by 47 percent in the high oil price scenario.

Shell estimated transportation capital costs to be approximately $12 million (1988) by TransCanada and $3.2 million (1988) by NOVA. Shell included a credit for facilities life remaining after the export term in its benefit-cost analysis.

Shell estimated the user costs associated with its proposed export based on the supply cost estimates and domestic demand forecasts outlined in the low and high oil price scenarios of the Supply/Demand Report. However, in forecasting export demand, Shell used a forecast of volumes expected to flow under existing licences. Shell's methodology results in a projection in which exports decline over time as the current export licences expire. Shell maintained that this approach was appropriate and that including a best-estimate projection of export demand would give precedence to licences not yet applied for, thereby placing an unwarranted burden on the current export applicants.

Shell's benefit-cost results indicated net benefits to Canada of $36 million in the low oil price scenario and of $38 million in the high oil price scenario, assuming an 8 percent discount rate.

In summary, Shell argued that Canadians would enjoy a social benefit from its proposed gas export.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

As explained in Appendix I of these Reasons, the Board used aggregate industry data to calculate by-product revenues and used a projection of exports rather than simply currently licensed exports to calculate the TIPC (including user costs). The Board's estimates of by-product revenues in respect of Shell's proposed export are much lower than those of Shell in both the low and high world oil price scenarios.

In its benefit-cost analysis, the Board has not included a credit for the social opportunity cost of labour or a social premium on foreign exchange. As is explained in Appendix I of these Reasons, the Board is not convinced that there are sufficient grounds to include such credits.

As is also explained in Appendix I of these Reasons, the Board is of the view that cogeneration plants are unlikely to achieve a load factor in excess of 90 percent. Therefore, the Board has used a load factor of 90 percent in assessing the net benefits to Canada that would be associated with this project. Sensitivity tests were conducted at 85 and 93 percent load factors. Lower sales volumes would have the effect of reducing the revenues, the TIPC and the variable transportation costs.

The Board finds that Shell's estimates of Niagara Mohawk's avoided costs are reasonable for calculating the gas sales revenue associated with the applied-for volumes. However, the Board's control case projection of export prices differs slightly from that of Shell because of different assumptions on the exchange and inflation rates. The Board used inflation and exchange rates consistent with the Supply/Demand Report assumptions, so as to be consistent with other supply and demand data used in its analyses.

Shell assumed a constant exchange rate of $0.80 U.S./Cdn and a constant inflation rate of 4.5 percent for both the low and high oil price scenarios. The Board's exchange rate is higher than Shell's in the first years and lower thereafter under both the low and high oil price cases. The Board assumed an inflation rate which is generally lower than Shell's in the low case and higher in the high case.

The results of the Board's control case benefit-cost analysis and sensitivity studies (shown in Tables 6-3 and 6-4, respectively) indicate that Shell's proposed export is unlikely to generate net benefits to Canada. The applied-for exports would provide net benefits to Canada only if the low world oil price scenario materialized and the export price escalation rate were 20 percent higher than used in the control case.

Table 6-2

Shell's Benefit-cost Analysis of its Proposed Export to CETI
(millions of 1988$, discounted at 8 percent)

	High World Oil Price	Low World Oil Price
Benefits		
Export Revenue	129	111
By-product Revenue	60	46
Social Premium on Foreign Exchange	6	6
Total Benefits	195	162
Costs		
Transportation Costs	28	28
TIPC		
User Costs	82	50
Direct Costs	53	53
Total Costs	163	131
Less		
Labour Externality	5.5	5.5
Net Benefits	38	36
Benefit/cost Ratio	1.24	1.29

Table 6-3

NEB Benefit-cost Analysis of Shell's Export Proposal
(millions of 1988$ discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Gas Export	114	127
By-product Revenue	16	24
Total Benefits	130	151
Costs		
TIPC	120	168
Transportation Costs		
Facilities Costs	26	26
Operating Costs	1	1
Total Costs	147	196
Net Social Benefits	(17)	(44)
Benefit/cost Ratio	0.89	0.77

Table 6-4

NEB Sensitivity Analyses of Shell's Export Licence Application
(millions of 1988$)

	Low Oil Price Scenario	High Oil Price Scenario
Control Case (R/P Ratio = 12)	(16.84)	(44.27)
Different Discount Rates		
6% Discount Rate	(24.58)	(64.38)
10% Discount Rate	(12.69)	(33.93)
Load Factor Sensitivities		
85% Load Factor	(14.49)	(41.13)
93% Load Factor	(16.69)	(46.14)
Export Price Escalation Rate		
10% Higher	(12.52)	(43.07)
10% Lower	(17.88)	(53.86)
20% Higher	0.02	(43.61)
20% Lower	(26.64)	(58.38)
No Facilities Credit	(19.71)	(48.02)
Different Supply Costs		
20% Higher	(27.72)	(59.31)
20% Lower	(3.22)	(29.41)
R/P Ratio = 15	(29.95)	(65.52)
Different Demand Forecasts		
Export @ 1.2 EJ/yr	(9.98)	(30.97)
Export @ 1.8 EJ/yr	(24.05)	(51.82)

6.9 Disposition

In arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia,* whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. Under this procedure the Board considers the EIA and complaints by Canadian gas-users taking into account current conditions in Canadian gas markets. In this regard, the Board noted the absence of any complaints or opposition to the proposed export. Shell submitted an EIA which demonstrated that the proposed export would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, transportation arrangements and the expected net benefits to Canada associated with the proposed export.

The Board is satisfied with the adequacy of Shell's overall gas supply and is of the view that Shell would be able to satisfy its total requirements throughout the term of the proposed export.

With respect to Shell's evidence on markets and contractual arrangements, the Board considers that the CETI cogeneration project would likely operate at a high load factor. However, the Board is concerned that the proposed export sales arrangements between Shell/Salmon/CETI are unlikely to provide for sufficient flexibility to allow adjustments to reflect changing market conditions. The Board notes that during the early years of the contract the price remains essentially fixed and in real terms is forecasted to decrease. The Board also notes that the contract price does not escalate at the same rate as the WAFT until after the thirteenth year and that the prices of No. 6 fuel oil and coal weigh heavily in the pricing escalator. Finally, the absence of a renegotation clause during the proposed 20-year term of the contract tends to compound the Board's concerns in this regard.

The Board assessed Shell's benefit-cost analysis of the export proposal and found, for reasons related primarily to differences in methodology, that the Board cannot agree with Shell's evaluation. In this regard the Board has found that Shell's proposal is not likely to generate net benefits to Canada. The sensitivity analyses performed by the Board supported this finding.

In conclusion, the Board is not satisfied that the proposed export is in the public interest. The Board is concerned that the sales contract terms and conditions may not provide sufficient flexibility in order to allow adjustments to reflect changing market conditions over time. The Board is also of the view that the applied-for export is unlikely to generate net benefits to Canada. Therefore, the Board denies Shell's application for an export licence.

Chapter 7

Western Gas Marketing Limited

7.1 Application Summary

By application dated 15 February 1989, as amended, WGML sought, pursuant to Part VI of the Act, a natural gas export licence with a term of 15 years for sales near Cornwall, Ontario to Megan-Racine Associates, Inc. ("Megan-Racine").

The gas proposed for export would be purchased by WGML from pools, fields and areas within Alberta. The gas would be transported by NOVA and TransCanada to an interconnection with the Niagara Gas Transmission Limited ("Niagara Gas") system. Niagara Gas would transport the gas to the international boundary at Cornwall, Ontario. At this point, St. Lawrence Gas Company, Inc. ("St. Lawrence Gas") would take delivery and ship the gas on its system to Megan-Racine's cogeneration facility.

Megan-Racine intends to construct and operate a cogeneration plant at Canton, New York. Megan-Racine has entered into an Agreement for the sale to Niagara Mohawk of the electricity produced at the cogeneration plant. It has also entered into a Steam and Chilled Water Purchase Agreement with Kraft, Inc. ("Kraft").

WGML applied for a licence with the following terms and conditions:

Term	- 1 November 1990 or date of first deliveries for a period of 15 years.
Point of Export	- Cornwall, Ontario
Maximum Daily Quantity	- 331.0 10^3m^3 (11.7 MMcf)
Maximum Annual Quantity	- 121.3 10^6m^3 (4.3 Bcf)
Maximum Term Quantity	- 1 820.0 10^6m^3 (64.2 Bcf)
Tolerances	- 10 percent/day and 2 percent/year

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an EIA; and other factors which the Board considers relevant in its determination of the public interest including, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements, markets, and net benefits to Canada.

7.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the WGML export proposal.

7.3 Export Impact Assessment

WGML analyzed the impact of the combined total volume of exports proposed in its application and

that of WGML/TransCanada (see Chapter 8) under three price scenarios. The total applied-for volume of exports under the two aforementioned applications was estimated to represent less than 0.5 percent of the remaining established conventional reserves under the base case. The net decrease in gas reserves was estimated to be even smaller, at 0.2 percent of the reserves, since the increased cash flow to producers combined with the improved exploration economics afforded by the market expansion is expected to lead to the discovery and development of new reserves. WGML based this conclusion on a quantitative analysis of the relationships between production revenues and exploration activity and between the latter and additions to reserves.

WGML stated that within a framework of market-sensitive pricing, Canadian gas prices would be affected by the North American supply-demand balance, domestic supply costs and domestic prices of competing fuels. WGML concluded that the proposed exports would not significantly affect these main determinants of gas prices in Canadian markets.

With regard to the North American natural gas supply-demand balance, WGML stated that since the annual export volumes represented only about one-tenth of one percent of annual North American demand, they were unlikely to affect domestic gas prices through their impact on the supply-demand balance. The impact of the proposed exports on supply costs was also estimated to be small since additional exports would lead to significant reserves additions largely offsetting the reserves reductions associated with increased production. Finally, WGML stated that in the absence of any measurable impact of the proposed exports on domestic gas prices, Canadians would not be required to adjust their future gas requirements in any manner different from that in the absence of the exports.

Views of the Board

The Board agrees with WGML's conclusion that its applied-for export volumes should have little impact on Canadian production, consumption and prices of natural gas and that Canadian energy users would not have any difficulty in meeting their future energy requirements.

7.4 Gas Supply

7.4.1 Supply Contracts

WGML will obtain its gas supply from TransCanada, which has contracted its supply from approximately 750 producers and suppliers. Under a recent netback agreement, all supply contracts have been extended to the economic life of the reserves with the producers having the option to terminate a contract with four years notice prior to the expiry date.

7.4.2 Reserves

Table 7-1 shows that the Board's estimate of TransCanada's reserves is 28 percent lower than the estimate provided by WGML. This difference can be partially attributed to interpretation of pool performance and certain reservoir parameters. Additionally, differences arise due to interpretation of TransCanada's contract position in specific pools. The Board, on a continuing basis, is reviewing its estimates of the reserves of the substantial number of pools under contract to TransCanada in order to identify and understand the reasons for the noted differences.

Table 7-1

Comparison of Estimates of TransCanada's Remaining Marketable Gas Reserves with Applied-for Volumes
10^9m^3 (Tcf)

WGML[1]	NEB[2]	Applied-for[3] Term Volume
626.6	486.8	9.7
(22.1)	(17.2)	(0.02)

1 as of December, 1988
2 as of December, 1987
3 This is the sum of the volumes proposed to be exported by WGML to Megan-Racine (1.8 10^9m^3) and the volumes proposed to be exported by WGML/TransCanada (see Chapter 8) to Niagara Mohawk (7.9 10^9m^3). Together the volumes represent only a small portion of the total requirements of WGML and WGML/TransCanada.

In its analysis of WGML's gas supply, the Board recognized approximately 7 000 pools, almost all of which are in Alberta. They are distributed across most of the province and include all major producing horizons. Most of the pools are in Cretaceous zones in central and east-central Alberta. The Jurassic to Carboniferous zones include about 600 pools and are largely located in the Foothills area and north of the Deep Basin. The Devonian pools are fewer in number but contain fairly large reserves. These pools are located in the central and northern areas of Alberta.

Approximately 65 percent of TransCanada's reserves are contained in 200 pools, each with initial established reserves in excess of 1 000 10^6m^3 (35 Bcf). In contrast, only 16 percent of TransCanada's reserves are contained in approximately 5 600 small pools, each with initial established reserves less than 100 10^6m^3 (3.5 Bcf).

In summary, the Board's estimate of TransCanada's reserves is considerably lower than that of WGML as a result of differences in pool parameters, evaluation methods and interpretation of TransCanada's contractual interest in specific pools.

7.4.3 Productive Capacity

As TransCanada is both the main supplier of Canadian domestic gas requirements and a major exporter, an assessment of TransCanada's ability to satisfy its contractual commitments tends to be more complicated than such an assessment in respect of other companies.

Figure 7-1 shows TransCanada's estimates of requirements and productive capacity. The projection of productive capacity is based on TransCanada's estimate of reserves and requirements. The requirements projection includes evergreened domestic and export sales. TransCanada's estimates indicate that productive capacity will be adequate to meet requirements until about 1994.

FIGURE 7-1

TRANSCANADA'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY AND REQUIREMENTS

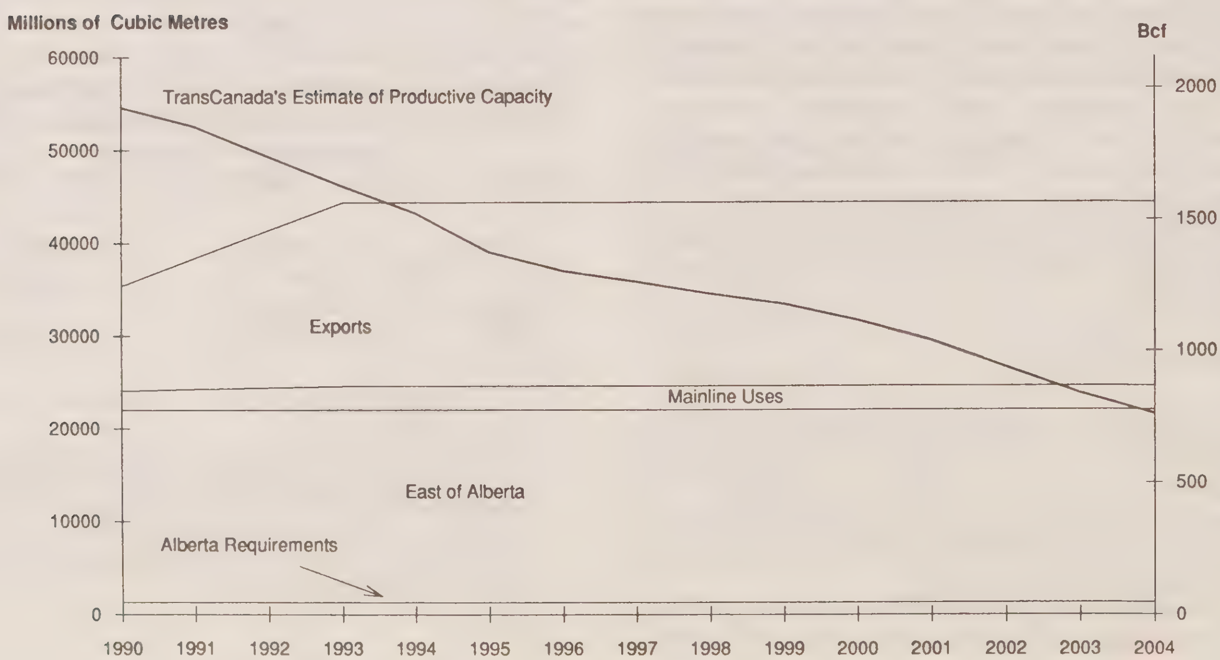


Figure 7-2 shows the Board's projections of TransCanada's requirements and productive capacity. The projection of productive capacity is based on the Board's assessment of TransCanada's reserves and requirements. The requirements estimates are the same as those used by TransCanada, with the exception of export sales. The Board has included only authorized export levels and the combined export volumes for Megan-Racine and Niagara Mohawk in its estimates. Corresponding changes were also made to the mainline uses estimates.

The Board's estimate of TransCanada's productive capacity assumes evergreening of domestic sales. As shown in Figure 7-2, existing contracts account for approximately one-half of TransCanada's anticipated domestic requirements over the majority of the projected period.

The Board's projection of TransCanada's productive capacity suggests potential deficiencies beginning as early as 1996, although the applied-for export volumes make little difference to TransCanada's total requirements.

Views Of The Board

The Board notes that its assessment of productive capacity is based on the assumption that domestic sales contracts will be evergreened. The Board is satisfied that if this assumption were not made, TransCanada would have sufficient supply to meet all of its current contractual commitments.

7.5 Energy Removal Authorization

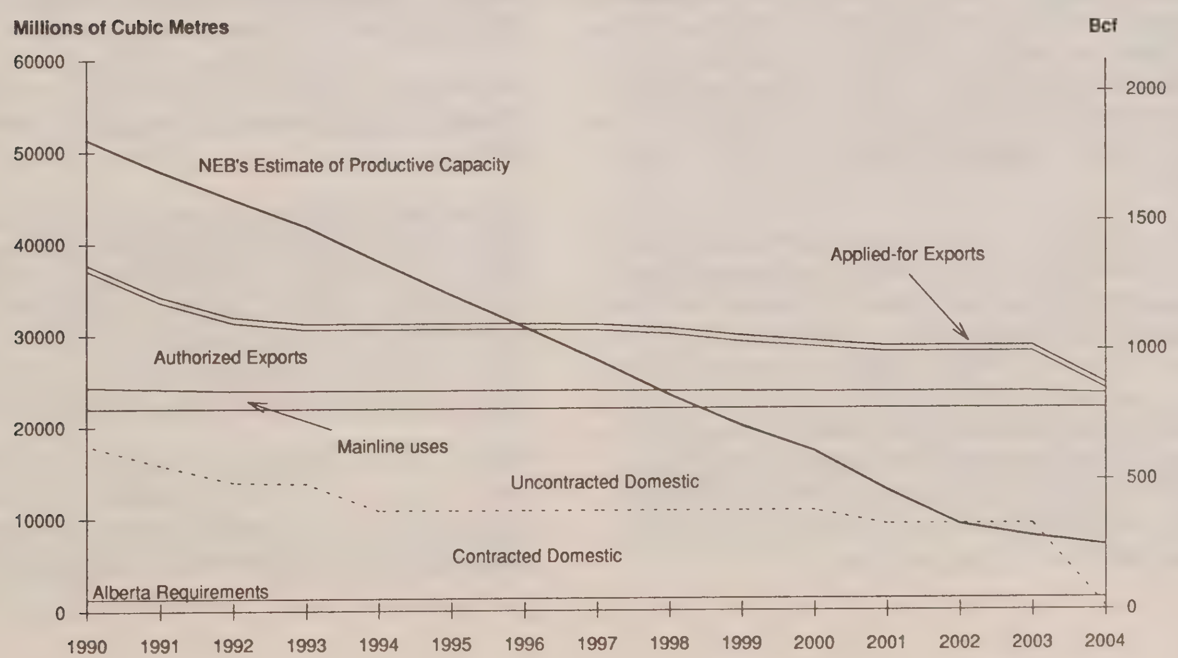
TransCanada holds several removal permits with the majority of its reserves included in removal permit TC 85-1. WGML stated that TransCanada would apply to the ERCB in the near future for a minor term extension to its removal permit in order to provide for the total sales requirements of WGML and WGML/TransCanada.

7.6 Market

WGML proposes to export natural gas to Megan-Racine which will construct a 49 MW combined cycle cogeneration plant in Canton, New York.

FIGURE 7-2

NEB'S ESTIMATES OF TRANSCANADA'S ANNUAL PRODUCTIVE CAPACITY AND REQUIREMENTS



WGML noted that the plant, which has QF status, would rely solely on Canadian gas.

Megan-Racine has signed an indefinite long-term Agreement with Niagara Mohawk for the sale of the electricity produced by the cogeneration plant. In addition, Megan-Racine will sell steam and chilled water to Kraft under a 15-year contract.

All required approvals and permits in the United States with respect to construction of the facility have been obtained, with the exception of the gas import licence for which an application to the Department of Energy's Office of Fossil Energy is expected to be made.

With respect to financing of the project, WGML testified that offers had been submitted by the Bank of New England and Credit Suisse but that Megan-Racine had not yet made a commitment to either. While the lending institutions do not require any financial guarantees in the way of support by parties other than Megan-Racine, they have indicated that an export licence must be obtained in order to break escrow.

WGML forecasts deliveries based on a load factor of 90 percent.

7.7 Contractual Arrangements

7.7.1 Transportation

Within Alberta, the gas would be shipped to Empress on the NOVA system. TransCanada would transport the gas to the Niagara Gas system for delivery onto the St. Lawrence Gas system. St. Lawrence Gas would then transport the gas on its system to the cogeneration facility in Canton, New York.

Transportation on NOVA has been secured under a 15-year firm contract. WGML has entered into a Precedent Agreement, signed in December 1988, with TransCanada for transportation. By letter dated 21 March 1989, Niagara Gas indicated that it is prepared to transport the requested volumes under a firm transportation service contract subject to receipt of regulatory approvals and installation, if required, of any additional facilities needed. Niagara Gas has not yet indicated whether additional facilities will be required.

In the United States, Megan-Racine signed a conditional agreement with St. Lawrence Gas dated 4 October 1988, for transportation from the border to the cogeneration plant. The agreement is conditioned on receipt of regulatory approvals including authorization to build a 12-mile pipeline linking the St. Lawrence system to the plant. It is anticipated that this work would be completed by the summer of 1990.

7.7.2 Sales Contract

WGML filed an executed precedent sales agreement entitled the Megan-Racine Precedent Agreement as well as a *pro forma* Gas Sales Contract that would be signed once all the conditions precedent have been satisfied. If all necessary permits, licences, regulatory authorizations, producer support, financing and transportation arrangements are not secured by 1 January 1991 the Megan-Racine Precedent Agreement can, upon 90 days notice, be declared null and void.

The Gas Sales Contract remains in force until 15 years after the date on which firm service is made available by TransCanada and Niagara Gas. After the tenth year the contract can be extended another five to 20 years, if parties agree.

The Gas Sales Contract provides for the daily delivery of up to 331 10^3m^3 (11.7 MMcf) commencing with the test phase of the facility. The contract recognizes that firm transportation service may not be available at that time, in which case, deliveries are to be made on a best-efforts basis only.

The contract includes a two-part pricing structure consisting of a demand charge and a commodity charge.

The demand charge component is made up of the sum of the applicable Canadian transportation charges on the NOVA, TransCanada and Niagara Gas systems plus a supply reservation fee of $4.563/Mcf of daily contract demand per month. Once firm deliveries start, the demand charges must be paid regardless of the volumes that flow.

The commodity charge component will be adjusted quarterly starting from an initial level of $U.S. 1.35/GJ ($U.S. 1.45/MMBtu) effective 1 April 1988. Adjustments to the commodity charge will be com-

prised equally of changes in Niagara Mohawk's avoided energy costs as provided by the NYSPSC as well as changes to the gas commodity component of CNG'S RQ Rate Schedule which is approved by the FERC. WGML testified that avoided energy costs would be affected by the prices of oil, gas, coal, nuclear power and purchased electricity, oil being dominant with a weight of approximately 80 percent. WGML estimated that from 1988 to 2005 inclusive, the avoided cost index would increase by 7.9 percent annually in nominal terms or almost 4 percent in real terms.

WGML testified that in March 1989, the border price would have been $U.S. 2.42/GJ ($U.S. 2.61/MMBtu)

Including U.S. transportation costs, the plant gate price would have been $U.S. 2.66/GJ ($U.S. 2.86/MMBtu) as of March 1989.

The contract allows for the renegotiation of the price or the price index every fifth year if the price is found to be non-competitive by either party. If such matters cannot be resolved by the parties, they will be settled by arbitration.

The contract also contains a 60 percent take or pay provision.

Views of the Board

The WGML/Megan-Racine *pro forma* Gas Sales Contract includes a pricing condition that provides for recovery of all fixed transportation costs on the NOVA, TransCanada and Niagara Gas systems in the form of a monthly demand charge.

The Board is satisfied that the contract would ensure recovery of all fixed costs.of transportation.

The commodity charge component of the export price is indexed equally to changes in the current average annual marginal avoided energy cost of Niagara Mohawk as estimated by the NYSPSC and the gas commodity component of CNG's RQ rate schedule as approved by the FERC. Furthermore, the contract provides for renegotiation and arbitration of the prices charged every fifth year during the contract term.

The Board is of the view that the pricing provisions contained in the WGML/Megan-Racine *pro forma* Gas Sales Contract permit adjustments in the export price to reflect changing market conditions. The Board also recognizes the flexibility that is in the agreement through the inclusion of a renegotiation and arbitration condition.

The Megan-Racine/Niagara Mohawk Agreement provides for electricity purchases by Niagara Mohawk for at least 336 days per year, during which time the cogeneration plant will require natural gas as fuel. The WGML/Megan-Racine *pro forma* Gas Sales Contract includes a 60 percent annual take or pay provision.

In the Board's view the contract provisions for minimum take, coupled with the likely prospect that the Megan-Racine plant will operate at a high load factor, will ensure adequate take levels under the Gas Sales Contract.

WGML filed evidence of a finding of producer support for the proposed Megan-Racine sale.

7.8 Benefit-cost Analysis

The benefit-cost analysis prepared by WGML in respect of its proposed natural gas export to Megan-Racine is summarized in Table 7-2. WGML's analysis indicated that this project was likely to generate net benefits to Canada.

The WGML/Megan-Racine *pro forma* Gas Sales Contract specifies a two-part price consisting of a demand and a commodity component. The demand charge component includes the TransCanada and NOVA demand tolls and a supply reservation fee. The commodity component is initially $U.S. 1.45/MMBtu and is escalated annually. The escalation index is defined as the ratio of Niagara Mohawk's prevailing marginal avoided energy cost to a base value multiplied by 0.5 plus the ratio of CNG's RQ Commodity Gas Rate to a base value multiplied by 0.5. For its analysis WGML assumed that CNG's RQ Commodity Gas Rate would escalate by two percent annually in the low oil price case and by between 3.8 and 6.3 percent annually in the high oil price case from 1990 to 2005.

Gas by-product revenues were expected by WGML to average 22 percent of the gas export revenue. By-product revenues amounted to $26.3 million in the low oil price case and $25.1 million in the high oil price case.

WGML used the supply cost estimates, productive capacity schedules and domestic natural gas demand projections found in the Supply/Demand Report to calculate the user cost associated with the gas export volumes. However, WGML's forecast of exports was based only on those volumes expected to flow under existing licences.

WGML argued that this was the appropriate methodology for determining the user cost attributable to its proposed export because using a forecast of exports would have the effect of allocating some of the user costs attributable to future applications to its current application.

WGML's estimates of the TransCanada, Union and Great Lakes facilities costs were taken from information provided by TransCanada. NOVA capital costs were estimated to be $3.3 million to be spent in 1996 and 1997.

In summary, WGML concluded that its proposed gas export under the Megan-Racine contract was likely to generate net benefits to Canada.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

As explained in Appendix I of these Reasons, the Board used aggregate industry data to calculate by-product revenues and used a forecast of exports rather than simply currently licensed exports to calculate the TIPC (including user costs).

The Board adopted WGML's load factor assumption of 90 percent and performed sensitivity tests at 85 and 95 percent load factors. In estimating the incremental capital costs associated with the transportation of the proposed export, the Board has included a credit for the useful economic life of the facilities after the term of the exports.

The Board did not use WGML's assumptions regarding the projected CNG RQ Commodity Gas Rate. The Board's CNG price projections were determined using assumptions and data taken from the Supply/Demand Report so as to ensure that the analysis was internally consistent.

The Board is of the view that the North American gas market is largely an integrated competitive market. For this reason, the Board expects that CNG's delivered gas prices should not be significantly different from the cost of Alberta gas delivered to this market. An estimate of the non-gas component of the commodity charge and the demand charges was subtracted from the Board's projection of CNG's gas rate to derive the commodity portion of the CNG gas price. This forecast of CNG's commodity gas rate was used to calculate the index.

The results of the Board's control case benefit-cost and sensitivity analyses (summarized in Tables 7-3 and 7-4) indicate that under a wide range of plausible assumptions, the applied-for exports are likely to generate net benefits to Canada.

Table 7-2

WGML's Benefit-cost Analysis of its Proposed Export

(millions of 1989$ discounted at 8 percent)

	Low User Cost Case	**High User Cost Case**
Benefits		
Gas Exports	109.5	125.5
By-products	26.3	25.1
Total Benefits	135.8	150.6
Costs		
Production Costs		
Capital	3.7	3.7
Operating	13.1	13.1
Transportation Costs		
Capital	26.9	26.9
Operating	14.0	15.9
User Costs	31.1	64.1
Total Costs	92.2	127.1
Net Social Benefit	47.0	26.9
Benefit/Cost Ratio	1.47	1.18

Table 7-3

NEB Benefit-cost Analysis of WGML's Export Proposal
(Million of 1989$ discounted at 8 percent)

	Low Oil Price Scenario	High Oil Price Scenario
Benefits		
Gas Revenue	116.4	134.4
By-product Revenue	14.6	21.9
Total Benefits	131.0	156.3
Costs		
Transportation Costs		
Capital	23.2	23.1
Operating	1.0	1.0
TIPC	99.4	137.8
Total Costs	123.7	162.0
Net Social Benefits	7.3	(5.7)
Benefit/Cost Ratio	1.06	0.97

Table 7-4

NEB Sensitivity Analyses of WGML's Export Licence Application
(millions of 1989$)

	Low Oil Price Scenario	High Oil Price Scenario
Control Case (R/P Ratio = 12)	7.3	(5.7)
Different Discount Rates		
6% Discount Rate	3.2	(16.2)
10% Discount Rate	7.3	(2.1)
Load Factor Sensitivities		
85% Load Factor	7.7	(4.6)
95% Load Factor.	6.8	(7.1)
Different Energy Charge		
10% Higher Index	15.2	4.0
10% Lower Index	(0.6)	(15.3)
No Facilities Credit	1.7	(11.3)
Different Supply Costs		
20% Higher	(3.8)	(18.6)
20% Lower	18.2	7.1
R/P Ratio = 15	(2.5)	(22.2)
Different Demand Forecasts		
Exports @ 1.2 EJ/yr	9.3	3.9
Exports @ 1.8 EJ/yr	2.0	(11.0)

7.9 Disposition

The Board has decided to issue a new gas export licence to WGML. In order for the licence to take effect, Governor in Council approval thereof is required. Appendix II contains the terms and conditions of the proposed licence which includes a condition that states that the term of the licence shall commence on the date that Governor in Council approval is received and shall end on 31 October 1991, unless exports have commenced on or before 31 October 1991, in which case the term will end on 31 October 2005.

In arriving at its decision the Board used its Market- Based Procedure to determine, *inter alia,* whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. Under this procedure the Board considers the EIA and complaints by Canadian gas-users taking into account current conditions in Canadian gas markets. In this regard, the Board noted the absence of any complaints or opposition to the proposed export. WGML submitted one EIA prepared in respect of its sale to Megan-Racine and WGML/ TransCanada's sale to Niagara Mohawk, which demonstrated that the combined exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts,

transportation arrangements and the expected net benefits to Canada associated with the proposed export.

In its assessment of gas supply the Board reviewed WGML's estimates of TransCanada's reserves and productive capacity and compared those estimates with its own. The Board notes that WGML's estimates indicate that if the new exports are imposed on a base demand that assumes evergreening of existing sales, productive capacity from existing supply falls below requirements by 1994 (see Figure 7-1). Based on assuming evergreening of domestic sales only, potential productive capacity deficiencies begin as early as 1996 (see Figure 7-2). Productive capacity appears sufficient, however, under the assumption that no evergreening of domestic or export sales is included in requirements. Considering the relatively small exports involved, the Board is prepared to accept WGML's demonstration of supply. Accordingly, the Board is satisfied that WGML has adequate gas supply to meet its currently contracted domestic and export sales requirements including the proposed sale to Megan-Racine.

With respect to WGML's evidence on markets and contractual arrangements, the Board believes that the proposed export to Megan-Racine will occur at a high load factor. Furthermore, the Board is satisfied that the export sales contract includes terms and conditions permitting sufficient flexibility to ensure responsiveness to changing market conditions as well as to ensure a high level of take.

The Board's review of the net benefits to Canada expected to result from WGML's proposed export indicates that the project is likely to generate net benefits to Canada.

Chapter 8

Western Gas Marketing Limited as agent for TransCanada PipeLines Limited

8.1 Application Summary

WGML/TransCanada applied on 14 February 1989, pursuant to Part VI of the Act, for a new natural gas export licence with a term of 15 years for sales to Niagara Mohawk at a point near Gananoque, Ontario.

The gas to be exported would be produced in Alberta from contracted lands and would be shipped through the NOVA and TransCanada systems to the international border near Gananoque, Ontario. Niagara Mohawk would take delivery of the gas at this point through a new extension of its pipeline system from Watertown, New York.

Niagara Mohawk is an electric and gas utility serving customers in the central, northern and eastern portions of upstate New York. It intends to use the proposed export as part of its system supply.

WGML/TransCanada applied for a licence with the following terms and conditions:

Term	- From the date all facilities, approvals, licences and agreements are in place for a term of 15 years.
Point of Export	- Gananoque, Ontario
Maximum Daily Quantity	- 1 445.0 10^3m^3 (51.0 MMcf)
Maximum Annual Quantity	- 529.0 10^6m^3 (18.7 Bcf)
Maximum Term Quantity	- 7 910.0 10^6m^3 (279.2 Bcf)
Tolerances	- 10 percent/day and 2 percent/year

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an EIA; and other factors which the Board considers relevant in its determination of the public interest including, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements, markets, and net benefits to Canada.

8.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the WGML/TransCanada export proposal.

8.3 Export Impact Assessment

WGML/TransCanada submitted an EIA for its sale to Niagara Mohawk and for WGML's sale to Megan-Racine on a combined basis. Discussion of the EIA is found in Section 7.3 of these Reasons.

8.4 Gas Supply

The gas supply for WGML/TransCanada will be provided by TransCanada. A detailed description of TransCanada's supply is found in Section 7.4 of these Reasons.

8.5 Energy Removal Authorizations

As described in Section 7.5 of these Reasons, WGML/TransCanada would use existing energy removal authorizations to serve this project.

8.6 Market

Niagara Mohawk is an electric and gas utility located in Syracuse, New York serving central, eastern and northern New York State. WGML/TransCanada stated that Niagara Mohawk had traditionally received all of its gas supply from CNG but was attempting to diversify its existing supply portfolio through acquisition of Canadian supply. The exports proposed by WGML/TransCanada would be used in Niagara Mohawk's central New York market area.

WGML/TransCanada provided a forecast of Niagara Mohawk's gas requirements for the period 1989 through 1999 which showed that total gas requirements are forecasted to increase approximately 25 percent, from 115 Bcf to 145 Bcf. The majority of the increase in gas requirements is projected to occur for power cogeneration which WGML/TransCanada showed increasing from 2 Bcf per year in 1989 to 30 Bcf per year by 1999 while residential/commercial requirements are projected to increase from 78 Bcf per year to only 80 Bcf per year during the same period.

WGML/TransCanada stated that large volume accounts within Niagara Mohawk's market area had almost all opted for direct sales and now utilized Niagara Mohawk solely for transportation service. These accounts would normally have represented about 25 percent of Niagara Mohawk's market requirements. WGML/TransCanada indicated that transportation service was not likely to further erode Niagara Mohawk's firm market requirements since the majority of large accounts had already switched to transportation service. WGML/TransCanada felt that Niagara Mohawk's forecasted increase of 2 Bcf in the residential/commercial market segment was conservative since it was based on historical patterns and did not take into account any increased marketing activity that Niagara Mohawk expects to undertake in the near future.

WGML/TransCanada stated that Niagara Mohawk's current agreements with CNG allow Niagara Mohawk to purchase gas in excess of a base quantity of 30 Bcf per year from other sources, primarily in the spot market.

8.7 Contractual Arrangements

8.7.1 Transportation

The proposed export volumes for Niagara Mohawk would be transported within Alberta by NOVA for delivery to the TransCanada system. TransCanada would then deliver the gas directly to the Niagara Mohawk system at the Gananoque, Ontario export point.

WGML/TransCanada indicated that it would transport the proposed exports within Alberta under TransCanada's existing long-term firm transportation arrangements with NOVA. As well, WGML has executed a transportation Precedent Agreement with TransCanada. In order to provide service to WGML/TransCanada's buyer, Niagara Mohawk, TransCanada must construct a 25.6-kilometre extension ("the Gananoque Extension") and metering station estimated to cost $23 million.

In order to receive the gas Niagara Mohawk must construct the Trans-York Extension, an extension of its distribution system, from its existing market area to the point of interconnection with TransCanada at the international boundary.

WGML/TransCanada indicated that the Trans-York Extension would not be subject to the FERC's authorization because the facilities are for intrastate service only. Niagara Mohawk would be required to apply to the FERC for a Presidential Permit granting Niagara Mohawk authority to operate the facility which crosses the international border. Niagara Mohawk has applied to the NYSPSC for authority to construct the Trans-York Extension and does not anticipate any difficulty in obtaining the required authorizations prior to the proposed commencement date for the exports.

8.7.2 Sales Contract

WGML/TransCanada filed an executed precedent sales agreement between TransCanada and Niagara Mohawk entitled the TransCanada/

Niagara Mohawk Precedent Agreement. The contractual terms and conditions of the sale are included in the *pro forma* Gas Purchase Contract attached to the precedent agreement.

The *pro forma* Gas Purchase Contract provides for sales at Gananoque, Ontario but also provides for alternate delivery points at Niagara Falls, and Iroquois, Ontario.[1] The daily contract quantity under the contract is 1 441 10^3m^3 (51 MMcf) for a term of 15 years commencing 1 November 1990 or upon receipt of all necessary approvals.

The contract includes a provision requiring Niagara Mohawk to purchase gas at a minimum load factor of 60 percent. In the event that Niagara Mohawk were to take less than 60 percent of the annual contract quantity, the shortfall would be added to the following year's minimum annual contract quantity.

In the event that a direct sale to a Niagara Mohawk customer were to occur through the Trans-York Extension, the contract provides for either a reduction in the daily quantity, a corresponding reduction in the demand charge rate payable by Niagara Mohawk, or both.

The contract includes a provision whereby TransCanada agrees to maintain its R/P Ratio above a factor of 10 on a rolling basis for consecutive five year periods during the term of the contract. If TransCanada found, upon review of its established reserves, that the Reserves to Production Ratio ("R/P Ratio") fell below 10, then it would first curtail short-term sales and then, if necessary, pro rate long-term sales.

Under the gas sales contract, Niagara Mohawk pays the full TransCanada and NOVA demand charges, a supply administration fee and a commodity charge. The commodity charge is the difference between the ABP and the demand charges. The ABP is equal to $U.S. 2.24/MMBtu for deliveries of up to 60 percent of the monthly contract quantity and $U.S. 2.19/MMBtu for those takes greater than 60 percent of the monthly contract quantity, adjusted monthly by an index. The index is the ratio of the then current CNG 100 percent load factor price to a base price of $U.S. 3.1516/MMBtu. WGML/TransCanada assumed that from 1990-2005 the index would increase by 2 percent per year in the low case and by 3.8 to 6.3 percent in the high case.

The contract permits renegotiation of the export price annually by either party. However, WGML/TransCanada is not permitted to request renegotiation during the second or third contract years unless the average of the monthly ABP's for the contract year is less than the Canadian Delivered Price for WGML's and TransCanada's sales in TransCanada's Eastern Toll Zone. Prices resulting from renegotiation or arbitration shall not be greater than any of:

- a ceiling price based on Niagara Mohawk's other long-term supply prices;
- the weighted average price of WGML and TransCanada for sales in TransCanada's Eastern Toll Zone; or
- other TransCanada prices negotiated in the northeastern United States.

Although under the contract the demand charge is subject to renegotiation, the contract provides that the NOVA and TransCanada fixed costs of transportation shall continue to be part of the demand charge.

WGML/TransCanada indicated that based on the pricing mechanism in the contract the 100 percent load factor price in March 1989 for sales to Niagara Mohawk would have been $U.S. 2.55/MMBtu.

Views of the Board

The Board has reviewed the terms and conditions of the WGML/TransCanada Gas Purchase Contract with Niagara Mohawk. The contract pricing provisions include a two-part rate consisting of a monthly demand charge and a commodity charge.

The Board is satisfied that under the terms of the contract the demand charge component of the export price will ensure recovery of all fixed costs of transportation in Canada.

The commodity component of the export price is indexed to the 100 percent load factor price for all other long-term suppliers of firm gas to Niagara Mohawk in that market area. At this time the only such supplier is CNG. The Board finds that the

1 WGML/TransCanada's application for an export licence seeks approval for exports at Gananoque only. Exports at Niagara Falls, or Iroquois, Ontario, if required, would be made pursuant to short-term export orders.

index used to escalate the adjusted base price in the contract has a strong downward bias resulting from the high price used in the denominator of the formula. As a consequence, the prices generated by the index are unlikely to fully reflect market conditions.

The contract provides that in the event Niagara Mohawk does not take at least 60 percent of the annual quantities available to it in any year, Niagara Mohawk agrees to make up the deficiency during the following contract year. In the event that Niagara Mohawk fails to make up the deficiency, WGML/TransCanada may reduce the daily contract quantity in proportion to the volume not taken. The contract also includes provision for yearly negotiation and arbitration of the prices in the event that the index proves to be inappropriate. During the second or third years of the contract term, WGML/TransCanada can only request renegotiation if the price being paid is less than prices being paid for gas delivered by WGML and TransCanada for sales in eastern Canada.

WGML/TransCanada submitted that Niagara Mohawk's market offered strong growth potential for system supply particularly in light of the competitive price available under the contract and the flexibility of the contract with respect to renegotiation opportunities to ensure price competitiveness.

The Board agrees with WGML/TransCanada that the Niagara Mohawk market proposed to be served under this agreement would likely take the gas at a high load factor given the lower price which will prevail for this supply as compared to Niagara Mohawk's alternative gas supplies.

Although the Board views the inclusion of a renegotiation clause in the contract as a positive feature, the Board is not persuaded, that in the circumstances of this case, there is a strong potential for the price of the gas proposed for export to achieve market value.

WGML/TransCanada filed evidence of producer support for the Niagara Mohawk export proposal.

8.8 Benefit-cost Analysis

The benefit-cost analysis that WGML/TransCanada submitted with its gas export licence application indicated that its proposed gas export to Niagara Mohawk would likely generate net benefits to Canada. The results of that analysis are summarized in Table 8-2.

WGML/TransCanada's analysis incorporated low, base and high cases which reflected differing assumptions on supply and demand conditions in North American gas markets. WGML/TransCanada's low and high case scenarios do not correspond directly to the Board's low and high world oil price scenarios because they are not predicated on the same general gas market conditions as those found in the Supply/Demand Report.

Under the Gas Purchase Contract, Niagara Mohawk pays the full TransCanada and NOVA demand charges, a supply administration fee and a commodity charge.

WGML/TransCanada included by-product revenues, expected to average 22 percent of the export revenues, as a benefit in its analysis. In response to a Board information request, WGML/TransCanada recognized that the supply costs that it adopted in its analysis already include a by-product revenue credit. Nevertheless, WGML/TransCanada supported the inclusion of by-product revenues on the basis that it would be inappropriate to mix generic and project-specific data in the same analysis. It argued that it would be inconsistent not to take into account the specific characteristics of the gas with respect to by-product content while at the same time using project-specific facilities costs.

In its calculation of the user cost associated with the applied-for export volumes, WGML/TransCanada used the supply cost estimates, productive capacity schedules and domestic natural gas demand projections provided in the Supply/Demand Report. However, WGML/TransCanada's forecast of exports was based only on those volumes expected to flow under existing licences. WGML/TransCanada defended using this forecast of exports by explaining that attributing any increases in unit production costs to all prospective future exports had the effect of allocating to the current application some of the user costs that should be attributed to future export applications.

WGML/TransCanada used information provided by TransCanada to estimate the incremental facilities costs on the TransCanada, Union and Great Lakes systems. NOVA costs were estimated at $7.7 million to reflect the cost of adding new facilities but were assumed to be incurred after the first five or six years of the contract as all of the capacity on the NOVA system that is required to accommodate

the additional volumes is presently under contract to WGML/TransCanada and no new facilities are necessary until then.

In summary, WGML/TransCanada concluded that its proposed gas export would likely generate net benefits to Canada under a wide range of plausible assumptions.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

As explained in Appendix I of these Reasons, the Board used aggregate industry data to calculate by-product revenues and used a forecast of exports rather than simply currently licensed exports to calculate the TIPC (including user costs). The Board's estimates of by-product revenues in respect of the WGML/TransCanada project is $63.7 million in the low oil price case and $95.5 million in the high oil price case. The Board's estimates of by-product revenues are lower than the WGML/ TransCanada estimates in both the low and high oil price cases.

The Board adopted WGML/TransCanada's load factor assumption of 90 percent in its analysis and performed sensitivity tests at 85 and 95 percent load factors.

The price index used in the contract is the ratio of CNG's prices to the base value of $U.S. 3.1516/ MMBtu. The Board did not use WGML/ TransCanada's assumptions regarding the future values of CNG's 100 percent load factor delivered price. The Board's CNG gas price projections were determined using assumptions and data taken from the Supply/Demand Report so as to ensure that the price projection is consistent with data used elsewhere in the analysis. The Board views the North American gas market as a largely integrated, competitive market. Therefore, the Board expects that CNG's delivered gas prices in this market area should not be much different than the cost of Alberta gas delivered to that market. The Board's estimate of the index in the TransCanada/Niagara Mohawk contract incorporates this assumption and is similar to WGML/TransCanada's index in the low oil price case and lower than WGML/TransCanada's index in the high oil price case.

In its benefit-cost analysis, WGML/TransCanada allocated the full cost of the Gananoque Extension directly to its proposed export. The Board reduced the allocation of the Gananoque Extension to 90 percent of the value used by WGML/TransCanada to reflect possible utilization of the facilities by other shippers. The Board also applied a further credit, recognizing these facilities would likely continue to be economically useful beyond the expiry of WGML/TransCanada's applied-for export licence.

The results of the Board's control case benefit-cost analysis and sensitivity studies (shown in Tables 8-3 and 8-4, respectively) indicate that WGML/ TransCanada's proposed export to Niagara Mohawk is unlikely to generate net benefits to Canada. The sensitivity studies support this finding in all cases.

The sensitivity analyses confirm that, under a wide range of plausible assumptions, the proposed WGML/TransCanada export is not likely to generate net benefits to Canada.

Table 8-1

WGML/TransCanada Benefit-cost Summary
(millions of 1989$, discounted at 8 percent)

	Low Case	Base Case	High Case
Benefits			
Gas Exports	488.7	527.9	609.1
By-products	117.3	116.1	121.8
Total Benefits	606.0	644.0	730.9
Costs			
Production Costs			
Capital	14.5	14.5	14.5
Operating	57.2	57.2	57.2
Transportation Costs			
Capital	137.4	137.4	137.4
Operating	62.6	67.3	77.1
User Cost	135.3	207.0	278.8
Total Costs	407.0	483.4	565.0
Net Social Benefit	199.0	160.6	165.9
Benefit/Cost Ratio	1.49	1.33	1.30

Table 8-2
NEB Benefit-cost Summary of WGML/TransCanada's Export Proposal
(millions of 1989$, discounted at 8 percent)

	Low Case	High Case
Benefits		
Gas Revenue	438.6	530.6
By-product Revenue	63.6	95.5
Total Benefits	502.2	626.1
Costs		
Transportation Costs		
Capital	115.7	115.2
Operating	4.5	5.0
TIPC	431.4	599.3
Total Costs	551.6	719.5
Net Social Benefit (Costs)	(49.4)	(93.4)
Benefit/Cost Ratio	0.91	0.87

Table 8-3

NEB Sensitivity Analyses of the WGML/ TransCanada Export Licence Application
(millions of 1989$)

	Low Oil Price Scenario	High Oil Price Scenario
Control Case (R/P Ratio = 12)	(49.4)	(93.4)
Different Discount Rates		
6% Discount Rate	(74.9)	(142.5)
10% Discount Rate	(41.7)	(74.3)
Load Factor Sensitivities		
85% Load Factor	(44.7)	(86.0)
95% Load Factor	(54.3)	(101.2)
Different Energy Charge		
10% Higher Index	(7.0)	(39.8)
10% Lower Index	(91.7)	(144.9)
No Facilities Credit	(80.6)	(124.6)
Different Supply Costs		
20% Higher	(93.4)	(149.5)
10% Lower	(2.0)	(37.4)
R/P Ratio = 15	(92.7)	(160.7)
Different Demand Forecasts		
Exports @ 1.2 EJ/yr	(47.5)	(50.6)
Exports @ 1.8 EJ/yr	(70.2)	(116.3)

8.9 Disposition

In arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia,* whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. Under this procedure the Board considers the EIA and complaints by Canadian gas-users taking into account current conditions in Canadian gas markets. In this regard, the Board noted the absence of any complaints or opposition to the proposed export. WGML/TransCanada submitted a combined EIA for its proposed export to Niagara Mohawk and for WGML's sale to Megan-Racine which demonstrated that the combined exports would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, transportation arrangements and the expected net benefits to Canada associated with the proposed export.

In its assessment of gas supply the Board reviewed WGML/ TransCanada's estimates of reserves and productive capacity and compared those estimates with its own. The Board notes that WGML/ TransCanada's estimate indicates that if the new exports are imposed on a base demand which assumes evergreening of existing sales, productive capacity from existing supply falls below requirements by 1994 (see Figure 7-1). Based on assuming evergreening of domestic sales only, potential productive capacity deficiencies begin as early as 1996 (see Figure 7-2). Productive capacity appears sufficient, however, under the assumption that no evergreening of domestic or export sales is included in requirements. Considering the relatively small exports involved, the Board is prepared to accept WGML/TransCanada's demonstration of supply. Accordingly, the Board is satisfied that WGML/ TransCanada has adequate gas supply to meet its currently contracted domestic and export sales requirements.

With respect to WGML/TransCanada's evidence on markets, the Board is of the view that the pro-

posed system sale to Niagara Mohawk would likely occur at a high load factor.

With respect to sales contract matters,the Board recognizes that the sales agreement does provide for the renegotiation of the pricing terms under certain conditions. However, notwithstanding this aspect of the contract, the Board is concerned that the price level used in the denominator of the formula exerts a downward bias on the ability of the prices generated for Canadian gas to fully reflect market conditions.

The Board also assessed the WGML/TransCanada benefit-cost analysis. The Board has concluded that the proposed export sale is unlikely to generate net benefits to Canada under the Board's control case and this finding was confirmed under a number of sensitivity tests. Capital costs related to construction of the Gananoque Extension contribute to this conclusion.

For these reasons the Board is not satisfied that the proposed WGML/TransCanada export sale to Niagara Mohawk is in the public interest. Therefore, the Board denies WGML/TransCanada's application for an export licence. As a result of this denial the Board notes that it will not be necessary to reopen the GH-1-89 hearing in order to hear further evidence related to the proposed Gananoque Extension.

Chapter 9

Direct Energy Marketing Limited

9.1 Application Summary

By application dated 12 October 1988, Direct Energy requested Board approval, pursuant to Part VI of the Act, for a new natural gas export licence authorizing the export of natural gas at Philipsburg, Quebec for a period of 15 years commencing 1 November 1989.

Direct Energy applied for a licence with the following terms and conditions:

Term	- 1 April 1990 to 31 March 2005 (15 years)
Point of Export	- Philipsburg, Quebec
Maximum Daily Quantity	- 171.0 10^3m^3 (6.0 MMcf)
Maximum Annual Quantity	- 62.4 10^6m^3 (2.2 Bcf)
Maximum Term Quantity	- 936.2 10^6m^3 (33.0 Bcf)
Tolerances	- 15 percent on the daily and 5 percent on the annual.

Direct Energy will purchase its gas supply in Alberta from five producers. The gas would be shipped through the NOVA and TransCanada systems to the international border at Philipsburg, Quebec, from which point it would be transported by Vermont Gas Systems Inc. ("Vermont Gas") to the proposed cogeneration facility to be constructed in East Georgia, Vermont.

The gas proposed for export would be purchased by Consolidated Fuels Company ("Consolidated") to fuel the cogeneration plant to be owned by Arrowhead Cogeneration Company Limited Partnership ("Arrowhead").

Section 118 of the Act requires the Board, in considering an application for a licence to export gas, to have regard to all considerations that appear to it to be relevant. In particular, the Board is required to satisfy itself that the quantity of gas to be exported does not exceed the surplus remaining after due allowance has been made for reasonably foreseeable Canadian requirements, taking account of trends in discovery.

To comply with the requirements of section 118 of the Act, the Board utilizes its Market-Based Procedure. This procedure includes consideration of the following: complaints, if any, under the complaints procedure; an EIA; and other factors which the Board considers relevant in its determination of the public interest including, the applicant's gas supply as it relates to reserves and productive capacity, upstream and downstream transportation arrangements, markets, and net benefits to Canada.

9.2 Complaints Procedure

The complaints procedure gives Canadian gas users an opportunity to object to an export proposal on the grounds that they have not had an opportunity to obtain additional supplies of gas under contract terms and conditions, including price, similar to those contained in the export proposal.

No complaints were received with respect to the Direct Energy export proposal.

9.3 Export Impact Assessment

Direct Energy concluded that the applied-for export volumes were too small to have any impact on the natural gas market in Canada. According to Direct Energy the annual applied-for export volumes represented about 0.07 percent of the forecast demand for Canadian gas including exports.

In this context, Direct Energy did not expect any additional conservation efforts or any necessity for fuel switching as a result of the proposed export. Direct Energy also felt it unlikely that the proposed export volumes would have any tangible impact on domestic prices of natural gas.

Views of the Board

The Board agrees with Direct Energy's overall conclusion that the applied-for export volumes should have little impact on Canadian production, consumption and prices of natural gas and that Canadian energy users would not have any difficulty in meeting their future energy requirements.

9.4 Gas Supply

9.4.1 Supply Contracts

Direct Energy has executed gas purchase contracts with five producers, namely, Blue Range Resources Ltd., Excel Energy Inc., Venwest Resources Ltd., Royal Trust Energy Corp. and Ranger Oil Ltd. The latter three producers are shareholders of Direct Energy.

Direct Energy stated that if shortfalls in gas supply were to occur, the individual producers were contractually obligated to provide the gas from other sources. Direct Energy's other producer/owners, who are not participating in this project, are not contractually committed to backstop the gas supply.

9.4.2 Reserves

Table 9-1 shows that the Board's estimate of reserves is 32 percent lower than Direct Energy's estimate and 23 percent lower than the applied-for volumes. This is primarily due to differences in the interpretation of net pay and pool area. The lower estimate of reserves represents the cumulative effect of small differences in the estimates for individual pools.

In its analysis of Direct Energy's gas supply, the Board recognized 28 gas pools in Alberta and one pool in British Columbia. The majority of these are small pools located in the east-central or plains area of Alberta. The pools are primarily in the Cretaceous, Mississippian and Devonian zones, with the Cretaceous Mannville Group accounting for the majority of reserves.

Table 9-1

Comparison Of Estimates Of Direct Energy's Remaining Marketable Gas Reserves With The Applied-for Term Volume
10^6m^3(Bcf)

Direct Energy[1]	NEB[2]	Applied-for Term Volume
1 061 (38)	723 (26)	936 (33)

1. as of May, 1989
2. as of December, 1988

Twenty-seven pools, for each of which Direct Energy's share of reserves is less than 65 10^6m^3 (2 Bcf), account for approximately one-half of Direct Energy's reserves and for about one-half of the total difference between the Board's and Direct Energy's estimates of reserves.

The Board's estimates of the small pool reserves are generally lower than Direct Energy's due to differences in the interpretation of net pay and/or area and, to a lesser extent, gas saturation and recovery factor. For seven pools, the Board's estimate of areal extent averages 70 percent of Direct Energy's estimates and for seven others the Board's estimate of net pay averages 58 percent of Direct Energy's estimate.

The two pools for which Direct Energy's share of reserves is greater than 65 10^6m^3 (2 Bcf) account for the remainder of the difference between the Board's and Direct Energy's estimate of reserves. These differences arise from the interpretation of area and net pay.

In summary, the reserves proposed to be relied upon by Direct Energy tend to be in small pools. The Board's estimates of the reserves are lower primarily due to differences in the interpretation of net pay and area in these pools.

9.4.3 Productive Capacity

Figure 9-1 compares the Board's and Direct Energy's projections of productive capacity with the applied-for volumes. Direct Energy intends to contract for fuel gas on a separate short-term basis and not necessarily from the same producers.

Direct Energy's projection of productive capacity indicates that it can meet the applied-for volumes throughout the term of the proposed export. The Board's projection suggests that Direct Energy cannot meet its requirements at any time during the proposed licence term. The difference in outlook is primarily attributable to the difference in estimates of reserves.

As noted earlier, Direct Energy intends to rely on its producer group should shortfalls in productive capacity occur. Direct Energy stated that it would also attempt to contract gas on a short-term basis if necessary.

Views Of The Board

The Board's estimate of Direct Energy's reserves is 23 percent lower than the applied-for term volume and the Board's projection of productive capacity does not meet requirements at any time during the proposed licence term. The Board's estimate of the shortfall in productive capacity ranges from 25 percent in 1996 to 60 percent in 2004. Furthermore, the Board notes that the gas purchase contracts between Direct Energy and its producer group are not supported by backstopping arrangements. Considering these factors, the Board is not satisfied with Direct Energy's gas supply arrangements.

9.5 Energy Removal Authorization

Direct Energy requires energy removal authorizations from Alberta and British Columbia. At the time of the hearing, an application had been submitted to the ERCB and a decision was pending. No indication was given as to the status of British Columbia removal authorization.

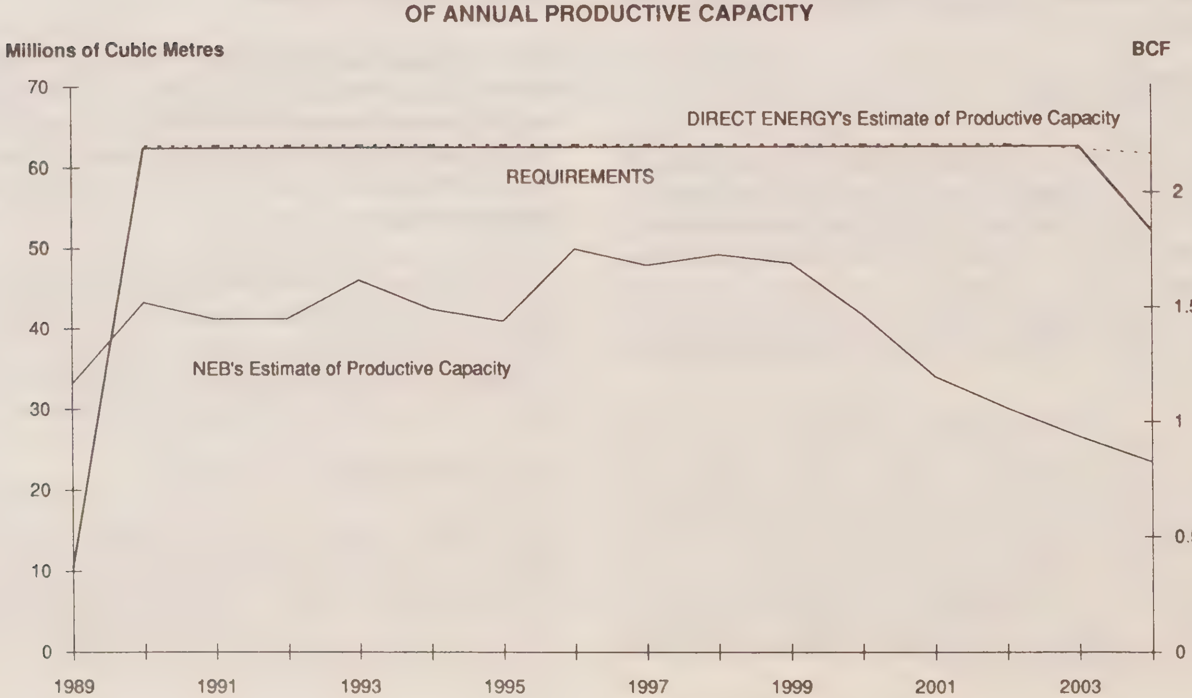
9.6 Market

Direct Energy proposes to export gas over a 15-year period to Consolidated. Consolidated will sell the gas to Arrowhead, which will own, operate and maintain a cogeneration facility to be constructed in Georgia, Vermont.

The Arrowhead plant is a 28 MW combined-cycle gas-fired cogeneration plant. Electric energy generated by the plant will be sold under a 20-year con-

FIGURE 9-1

COMPARISON OF DIRECT ENERGY'S & NEB'S ESTIMATES OF ANNUAL PRODUCTIVE CAPACITY



tract to the Unitil Power Corporation ("Unitil"), a public utility. The plant's steam production will be sold to Wyeth Nutritionals Inc. which owns a nearby dairy processing plant.

Arrowhead has applied to the State of Vermont for a permit to construct the plant. No opposition has been registered and approval is expected. Approval has been granted by the FERC for the plant to operate as a QF under the PURPA Regulations. Originally, the in-service date of the plant was expected to be 1 November 1989 and Direct Energy had requested that the licence also commence on that date. Direct Energy now expects the start date to be 1 April 1990.

Direct Energy stated that Arrowhead would only have access to Canadian gas. However, if the Champlain pipeline is constructed and tied into other U.S. pipelines, then U.S. gas could be delivered to the plant. The back-up fuel for the plant will be No. 2 fuel oil which would only be used in the event that Canadian gas was not available.

Direct Energy held the view that the facility would operate at a very high load factor and the applied-for export volumes reflect a 97 percent load factor.

With regard to financing, Direct Energy stated that a financial institution had reviewed the project and had provided a letter of commitment last year and that although that letter has expired, the commitment still exists.

Finally, Direct Energy indicated that the U.S. Department of Energy's Office of Fossil Energy had noted its application for an import permit, that there was no opposition and that approval was expected.

9.7 Contractual Arrangements

9.7.1 Transportation

The gas would be shipped within Alberta on the NOVA system to an interconnection with TransCanada at Empress for transportation from the Alberta/Saskatchewan border to the interconnection point with Vermont Gas near Philipsburg, Quebec.

By letter dated 30 August 1988, NOVA indicated its willingness to transport Direct Energy's gas once it had been authorized for removal and export. Direct Energy testified that firm service on NOVA would be available as of 1 November 1989 for about 70 percent of the gas. The remainder of the required NOVA transportation would become available on 1 November 1990.

In respect of transportation on the TransCanada system, Direct Energy filed a precedent agreement dated 14 October 1988. However, on 18 July 1988, TransCanada invoked its right to terminate the agreement as Direct Energy had not received approval from the Board to export the gas. In response to an application by Direct Energy, pursuant to section 59, and subsections 19(2), 71(2) and 71(3) of the Act, the Board issued Order No. TGI-2-89 on 27 July 1989 ordering TransCanada, until further notice, to reserve Direct Energy's capacity and queue position for the 1989/90 contract year.

The gas would be transported by Vermont Gas from the international border to the Arrowhead facility. In this regard, Direct Energy filed a letter dated 31 August 1989 between Consolidated and Vermont Gas, wherein Vermont Gas expressed willingness to provide the service. The Consolidated/Vermont Gas transportation contract is expected to be executed in the near future.

There will be a need to construct a three-mile long lateral from the Vermont Gas system to the Arrowhead plant. An application for the lateral has been filed with the Vermont Public Service Board and approval is expected in the fall of 1989.

9.7.2 Sales Contract

The gas proposed for export would be sold by Direct Energy to Consolidated which, in turn, would sell the gas to Arrowhead. Direct Energy filed a copy of the Direct Energy/Consolidated gas sales agreement dated 22 November 1988, as well as an executed copy of a Natural Gas Sale and Purchase Agreement between Consolidated and Arrowhead dated 15 March 1989.

The Direct Energy/Consolidated agreement provides for a Daily Contract Quantity ("DCQ") of 171.0 10^3m^3 per day (6 MMcfd), for a 15-year period, commencing with the start of commercial operation of the plant. There is also a provision for deliveries of unspecified volumes of gas in excess of the firm volumes on a best efforts basis. The agreement provides for a minimum annual load factor of 80 percent of the DCQ. Consolidated will endea-

vour to take a minimum daily volume of 114.0 10^3m^3 (4 MMcf). Under the agreement, if Consolidated requests, Direct Energy can sell to third parties any volumes not taken by Consolidated up to the DCQ level.

The agreement has a two-part demand and commodity pricing structure. In respect of the demand charges, the buyer is required to pay each month the sum of the transportation charges for NOVA and TransCanada, compressor fuel charges and take or pay cost-sharing levies. Direct Energy pointed out that in the event that TransCanada's tolls were to increase, such increases would be passed through to the U.S. buyer.

The commodity charge component of the export price is indexed to the NEPOOL Average Fossil Fuel Cost ("AFFC"). The NEPOOL AFFC index represents the average cost of fossil fuel to NEPOOL members to generate electricity and is sensitive to the demand for electricity and changes in fossil fuel prices.

The agreement provides for a commodity-based price as of July 1988 of $U.S. 1.004/MMBtu ($U.S. 0.93/GJ) which includes fuel costs for NOVA and TransCanada. Each month, the commodity charge would be re-calculated by multiplying the then-current base price by the ratio of the most recent NEPOOL AFFC to the NEPOOL AFFC for July 1988.

Direct Energy calculated that in March 1989 the border price would have been $U.S. 2.21/GJ ($U.S. 2.3818/MMBtu)

With the addition of the cost of transportation in the United States, the price as of March 1989 at the plant gate would have been $U.S. 2.63/GJ ($U.S. 2.8318/MMBtu).

The agreement does not include provision for the renegotiation of the pricing conditions.

Views of the Board

The export price in the Gas Sales Agreement includes a demand charge component which is made up of the NOVA and TransCanada fixed transportation cost. In this regard, the Board is satisfied that the associated fixed costs of transportation in Canada will be recovered in the export price.

The base price in the agreement is indexed to the weighted NEPOOL AFFC index which is broadly representative of fossil fuel costs for power generators in the New England market area.

Direct Energy stated that NEPOOL members currently generate electricity with fossil fuels (60 percent), nuclear (33 percent), conventional hydro (6 percent) and other means (one percent). The fossil fuel component is made up largely of oil (70 percent), while coal represents 27 percent of the index leaving 3 percent for natural gas utilization.

Direct Energy was of the view that the NEPOOL AFFC index would change over time because of environmental concerns. Direct Energy testified that while oil was expected to remain the primary fuel used, power generation facilities would be upgrading their fuel oil choices from high sulphur content to lower sulphur, higher-priced grades. Furthermore, as coal-fired plants are shut-down, they would likely be replaced by new gas-fired power plants. As a result higher-priced fuels would weigh more heavily in the NEPOOL AFFC index thereby providing higher gas prices under the sales agreement.

The Board does not dispute that the Direct Energy price is market-responsive insofar as the Direct Energy sale is being made to an electric power generation facility and the export price is tied to other fuels selling to this same market. However, the Board is of the view, as supported by evidence filed by Direct Energy, that the NEPOOL AFFC index, under the low oil price scenario, will only allow the export price to escalate at a moderate rate. Further, the Board is not persuaded that there will be any significant change in the fuel composition of the index over the contract term. These factors, when considered with the low initial base commodity price, as well as the lack of a renegotiation condition in the contract, lead the Board to conclude that this sales arrangement will not permit adjustments to reflect changing market conditions.

The export agreement contains an 80 percent take and pay provision. This, together with a gas price set to compete with primarily fuel oil and coal prices, should result in takes under the agreementt at a consistently high load factor level.

Direct Energy filed evidence indicating producer support for the proposed export sale to Consolidated.

9.8 Benefit-cost Analysis

The benefit-cost analysis submitted by Direct Energy indicated that its proposed gas export operating at a 100 percent load factor would yield positive results in its high case and its base case but negative benefits in its low case. Direct Energy performed sensitivity tests at an 80 percent load factor which showed negative results under both the high and low cases. These results are summarized in Table 9-2.

The Gas Sales Agreement specifies that Direct Energy is to be reimbursed for all transportation charges, compressor fuel charges, TOPGAS levies, and an energy charge. The energy charge for any month is calculated by multiplying the base price of $U.S. 1.004/MMBtu by the ratio of the NEPOOL AFFC for that month to a base AFFC value.

Direct Energy included by-product revenues in its total revenues, estimating the annual recovery to be at 5.1 million litres, valued at 12¢ per litre. The by-product price was assumed to escalate at the average of the escalation rates in the forecasts of high and low world oil prices from the Supply/Demand Report. Total by-product revenues were estimated at approximately $6.1 million, net present-valued at 8 percent.

In its estimate of the user cost attributable to its proposed gas export, Direct Energy used the low oil price forecast of domestic requirements found in the 1986 Supply/Demand Report. Direct Energy's forecast of exports is based on those volumes expected to flow under the then existing licences plus the Pan-Alberta and Alberta and Southern licences issued since that time. This forecast shows exports falling to zero by 2006. Direct Energy assumed a 100 percent load factor for its exports to calculate user cost. Direct Energy did not adjust its estimate of user cost to reflect differences resulting from operating at a lower load factor of 80 percent, or from higher or lower world oil prices (i.e., the user cost estimated by Direct Energy is the same in the low and high oil price cases under both 80 and 100 percent load factor assumptions as it is in Direct Energy's base case).

Based on information provided by TransCanada, Direct Energy estimated transportation facilities costs to be $15 million for TransCanada. Direct Energy testified that it was unable to estimate the incremental NOVA costs associated with its application and that it had made no allocation for Great Lakes costs since TransCanada had advised that no expansion would be required on Great Lakes in 1989.

Direct Energy submitted that its analysis demonstrated that its proposed gas export would generate economic benefits to Canada.

Views of the Board

The Board's views on the appropriate methodology to be used in a benefit-cost analysis are stated in Appendix I of these Reasons. The following views are based, among other things, upon Appendix I to which the reader is referred for further details.

As explained in Appendix I of these Reasons, the Board used aggregate industry data to calculate by-product revenues and used a forecast of exports rather than simply currently licensed exports to calculate the TIPC (including user costs). The Board's estimate of by-product revenues is higher than Direct Energy's by approximately $2 million in the low case and $6 million in the high case. TIPC has been calculated separately for each of the Board's assumed load factors and for the low and high case world oil price scenarios used in the Board's evaluation.

The Board adjusted transportation facilities costs upward to include an allocation for those incremental NOVA costs attributable to this project and to reflect slightly higher TransCanada costs. In the Board's judgment, higher costs on the TransCanada system better reflect the incremental costs expected over the forecast period of the proposed export. However, a credit was applied to the facilities costs so that the actual allocated cost of facilities is slightly lower than that used by Direct Energy.

As explained in Appendix I of these Reasons, the Board is of the view that cogeneration plants are unlikely to achieve a load factor in excess of 90 percent. Therefore, the Board has used a load factor of 90 percent in assessing the net benefits to Canada that would be associated with this project. Sensitivity tests were conducted at 85 and 95 percent load factors. Lower sales volumes would have the effect of reducing the revenues, the total increase in production costs and the variable transportation costs.

The revenue stream is also affected by the forecast of the NEPOOL AFFC index. The Board's forecast of

that index utilizes forecasts of fossil fuel prices incorporated in the Supply/Demand Report and is therefore consistent with the assumptions and methodology used in the remainder of the Board's analysis. In the low oil price case the Board's forecast of the NEPOOL AFFC index is higher than Direct Energy's for the years 1989-1997 and lower than Direct Energy's from 1998-2004. In the high oil price case, Direct Energy's forecast of the index is higher than the Board's except for the initial two years.

The Board's control case and sensitivity analyses (see Tables 9-3 and 9-4) indicate that Direct Energy's proposed export is unlikely to provide net benefits to Canada.

Table 9-2

Direct Energy's Benefit-cost Summary
(millions of 1989$, discounted at 8 percent)

100 percent Load Factor

	Base Case	Low Case	High Case
Benefits	63.2	57.3	63.5
Field & Transportation	28.7	28.7	28.7
Social Costs	30.1	30.1	30.1
Total Costs	58.8	58.8	58.8
Net Social Benefits	4.4	(1.5)	4.7
Benefit/Cost Ratio	1.07	0.97	1.08

80 percent Load Factor

	Low Case	High Case
Benefits	45.8	50.8
Field & Transportation	26.3	26.3
Social Costs	30.1	30.1
Total Costs	56.4	56.4
Net Social Benefits	(10.6)	(5.6)
Benefit/Cost Ratio	0.81	0.90

Table 9-3

NEB Benefit-cost Summary of Direct Energy's Export Proposal
(millions of 1989$, discounted at 8 percent)

90 percent Load Factor

	Low Case	High Case
Benefits		
Gas Sales Revenue	52.0	65.7
By-product Revenue	8.0	12.0
Total Benefits	60.0	77.7
Costs		
Transportation Costs		
Capital	12.4	12.4
Operating	0.6	0.6
TIPC	50.6	69.9
Total Costs	63.5	82.9
Net Social Benefit	(3.5)	(5.2)
Benefit/Cost Ratio	0.94	0.94

1 net present values to 1989

Table 9-4

NEB Sensitivity Analyses of Direct Energy's Export Licence Application
(millions of 1988$)

	Low Oil Price Scenario	High Oil Price Scenario
Control Case (R/P Ratio = 12)	(3.5)	(5.2)
Different Discount Rates		
6% Discount Rate	(6.0)	(10.1)
10% Discount Rate	(3.3)	(3.7)
Load Factor Sensitivities		
85% Load Factor	(3.0)	(4.7)
95% Load Factor	(4.1)	(6.0)
Different Energy Charge		
10% Higher	(0.5)	(0.9)
10% Lower	(6.5)	(9.5)
No Facilities Credit	(9.2)	(10.9)
Different Supply Costs		
20% Higher	(8.7)	(11.8)
20% Lower	2.0	1.3
R/P Ratio = 15	(8.2)	(13.0)
Different Demand Forecasts		
Exports @ 1.2 EJ/yr	(5.4)	(0.6)
Exports @ 1.8 EJ/yr	(6.1)	(7.8)

9.9 Disposition

In arriving at its decision the Board used its Market-Based Procedure to determine, *inter alia,* whether the volumes to be exported are surplus to reasonably foreseeable Canadian requirements. Under this procedure the Board considers the EIA and complaints by Canadian gas-users taking into account current conditions in Canadian gas markets. In this regard, the Board noted the absence of any complaints or opposition to the proposed export. Direct Energy submitted an EIA which demonstrated that the proposed export would have little or no impact on total production, gas prices or Canadian consumption patterns and that Canadian energy users would not have any difficulty in meeting their future energy requirements. Based on its review of these matters the Board is satisfied that the proposed export is surplus to reasonably foreseeable Canadian requirements.

As part of its Market-Based Procedure, the Board also assessed a number of public interest factors, including gas supply, markets, gas sales contracts, transportation arrangements and the expected net benefits to Canada associated with the proposed export.

The Board is not satisfied with the adequacy of Direct Energy's overall gas supply. The Board's estimate of Direct Energy's reserves was 23 percent lower than the applied-for volumes and the Board's projection of productive capacity indicates that Direct Energy would not be able to meet requirements at any time during the proposed licence term.

With respect to Direct Energy's evidence on markets and contractual arrangements, the Board is of the view that the cogeneration market offers good potential for high load factor sales and that the nature of the fuel requirements for the plant offers reasonable assurances of take. However, the Board is concerned that the Gas Sales Agreement does not provide for sufficient flexibility to allow adjustments to reflect changing market conditions.

The Board's assessment of Direct Energy's benefit-cost analysis indicates that the proposed export sale is not likely to generate net benefits to Canada under a broad range of assumptions.

In conclusion, the Board is not satisfied that the proposed export is in the public interest. The Board was not satisfied with Direct Energy's evidence on gas supply and is concerned with the terms and conditions of the Gas Sales Agreement. Furthermore, the Board is of the view that the applied-for export is unlikely to generate net benefits to Canada. Therefore, the Board denies Direct Energy's application for an export licence.

The foregoing chapters constitute our Reasons for Decision in respect of the GH-1-89 export applications.

A.B. Gilmour
Presiding Member

R.B. Horner, Q.C.
Member

K.W. Vollman
Member

Ottawa, Canada
December 1989

Benefit-cost Methodology and Assumptions

Export applicants used certain information from the 1986 and 1988 Supply/Demand Reports in their own cost-benefit analyses, and the Board's information request also drew on that source for specifying some standard assumptions. However, the Board does not consider that these assumptions are necessarily correct and that other assumptions are therefore incorrect. It is acknowledged that there is a degree of uncertainty surrounding most assumptions and projections relevant to benefit-cost analysis. Therefore the Board considers that sensitivity tests are an essential element of benefit-cost work.

In general, in its benefit-cost work on the applicants' proposals, the Board used the applicants' own assumptions in respect of those variables for which there was not a particularly compelling reason to do otherwise. In general, where the Board substituted its own assumptions for those of the applicant, it was with a view to achieving consistency, where appropriate, between those assumptions and related ones which applicants used from the Supply/Demand Report.

The benefits associated with a proposed gas export consist of the incremental gas export revenues and associated by-product revenues. The Board examined the reasonableness of the applicants' revenue estimates and for this purpose developed a projection of export prices underpinning each sales contract. This necessitated making assumptions under both the low and high oil price scenarios on the prices of U.S. natural gas, fuel oil and coal and on the U.S./Canada exchange rate. Also, since some contracts have pricing terms that incorporate nominal escalation rates, the Board developed a projection of Canadian and U.S. inflation rates in order to derive real 1988 present values used in its benefit-cost analyses.

The Board's projection of U.S. gas prices is based on the Canadian fieldgate prices included in the Supply/Demand Report plus all marketing fees, fuel gas charges, TOPGAS[1] levies and transportation costs incurred in Canada and the U.S. The Board's estimate of U.S. fuel oil prices is consistent with the projection of world oil prices included in the Supply/Demand Report. No growth in real prices of coal is expected to occur during the forecast period.

The Board's projection of the U.S. inflation rate is constant at 5.0 percent after 1991 in the high oil price scenario and at 4.0 percent after 1993 in the low oil price scenario. The Board's estimate of the Canadian inflation rate fluctuates between 3.5 and 5.0 percent in the low oil price case and between 4.0 and 6.0 percent in the high oil price case.

The Board developed a projection of the U.S./Canadian exchange rate which increases from \$0.813 U.S./Cdn to \$0.833 U.S./Cdn in 1989, decreases to \$0.781 U.S./Cdn in 1992 and stays constant at that level thereafter for both the low and high oil price scenarios.

The Board notes that most of the applicants proposing to export gas for sale to cogeneration projects assumed load factors equal to or close to 90 percent. The Board accepts that a 90 percent load factor for takes by cogeneration plants is reasonable. For sales to U.S. local distribution companies ("LDCs") for system supply, the Board is satisfied with the load factors as assumed by the relevant export applicants.

Because the sales contracts associated with each export licence application heard in the GH-1-89 proceeding require that the U.S. importer pay the transportation demand charges and, in some cases, also the transportation commodity charges incurred in Canada, those payments were treated

1 TOPGAS levies are charges included in TransCanada's Alberta cost of service. They are designed to recover interest payments on certain loans made to TransCanada's producers to alleviate TransCanada's take-or-pay liabilities.

as benefits to Canada. Most of the export applicants assumed that the demand and commodity charges on the NOVA and TransCanada systems would remain constant in real terms over the life of the contracts. It is the Board's view, however, that it is more appropriate to use a projection of TransCanada tolls in order to make these consistent with the overall supply, demand, and price projections underlying the scenarios applicable to the export proposal. Thus, for its evaluation of the export applicants' benefit-cost analyses, the Board developed toll projections based on assumptions consistent with the volume projections in the Supply/Demand Report. Since the NOVA toll accounts for a small share of the export revenues, the Board is satisfied with the assumption that it would remain constant in real terms over the life of the applied-for licences.

The costs associated with a proposed gas export consist of TIPC including direct production costs and user cost,[1] and incremental transportation costs.

The Board considers that, for the purpose of evaluating the incremental gas production costs to Canada associated with the proposed export projects, the volume forecast used should include export volumes expected to flow over the time period of the evaluation. In estimating the incremental production cost associated with each export proposal, the Board has used the projections of domestic and export demand from the Supply/Demand Report. The Board used the aggregate supply cost estimates for the low and high oil price scenarios from that report to estimate the incremental production costs attributable to each export proposal.

The primary difference between the Board's methodology and that used by the export applicants is that when calculating the TIPC associated with their applied-for exports, most applicants limited exports to the annual levels that were licensed at the time of the GH-1-89 Hearing. The Board, as noted above, used the projection of exports contained in the Supply/Demand Report.

Most of the export applicants, as well as TransCanada, were of the view that using a forecast of exports would be prejudicial to the export proposals before the Board in this proceeding. According to TransCanada, Amoco/Con Ed and Shell, using a forecast of exports would bring them higher on the supply cost curve with resulting higher user costs. WGML argued that such a methodology, by trying to treat current and future applications on a consistent basis, would have the effect of giving priority to export proposals not yet before the Board.

ProGas, WGML, and WGML/TransCanada argued that using a forecast of exports rather than exports that are currently licensed would change the basic nature of the question the Board addresses from whether it is beneficial to license additional exports to whether or not it is in the public interest to license an incremental export in light of expected future circumstances. ProGas indicated that even if other applications are likely to come before the Board, proponents of current applications should not speculate on whether such future applications will proceed and how much gas they will require.

The Board notes that user costs are related to the time profile of total gas production. Increased production from existing reservoirs brings forward in time the use of higher cost gas. Thus, the user cost associated with a proposed export is a function of the total Canadian gas production profile over time. Licensed exports would only be relevant to the estimation of user cost if they could reasonably be expected to approximate the level of actual exports.

It is the Board's view that using licensed exports as a basis for estimating incremental production costs could understate the exports that are likely to flow during the period covered by the applications and consequently could understate the incremental production costs associated with the proposed new gas exports. In the Board's view it is highly likely that exports will flow in the future at annual levels substantially in excess of licensed levels that were used by applicants in their submissions. This is so for a number of reasons:

- many industry analysts are projecting future export levels substantially in excess of volumes licensed at the commencement of the GH-1-89 Hearing;

1 New exports necessitate the development of more expensive gas reserves to meet domestic and other export demand sooner than would be the case in the absence of the new exports. The associated increase in the cost of meeting these other demands is called the user cost of the new exports.

- substantial quantities of exports have recently been flowing, and can be expected to continue to flow, under short-term orders; and

- existing pipeline capacity can accommodate export levels in excess of licensed quantities at the time of the GH-1-89 Hearing, and it is conceivable that additional export capacity will be built.

The Board concludes that to properly evaluate the user cost associated with the export applications before the Board in this proceeding the benchmark level of exports used must be in excess of the volume that was licensed at the outset of this hearing. To use the level of exports licensed at the outset of the hearing as the benchmark would be assuming that, absent the exports proposed, alternative market opportunities for Canadian gas would be non-existent. This is, in the Board's view, not warranted given current circumstances.

Another issue related to assessing the benefits associated with the export applications was whether to use aggregate industry supply cost and liquids yield data or applicant-specific data when calculating the total increase in production cost and by-product revenues. Indeck and Shell argued that it was not appropriate to use generic cost data because it penalizes projects that have gas with lower direct costs or higher by-product revenues and that are, as a consequence economically more efficient. WGML and WGML/TransCanada further argued that to assume generic industry costs, while allowing the revenues to reflect company-specific data, would have the effect of making the benefit-cost analysis a minimum price test. WGML further submitted that if that minimum price were found to be above the average price charged in the domestic market, the proposed methodology would be incompatible with the FTA

The Board is of the view that, in estimating the TIPC associated with an export licence application, the total production costs of satisfying future demand with the incremental export should be compared to the total production costs of satisfying future demand without the incremental export. The particular production costs of any export licence applicant, whether above or below the industry aggregate, are, in the Board's view, common to both the "with" and the "without" export scenarios and are therefore not a relevant factor in the estimation of the effective incremental production costs to meet an incremental demand.

The Board considers it reasonable to assume that producers in aggregate will behave rationally and exploit natural gas reservoirs by progressively moving from lower cost to higher cost reserves. Therefore, given that most export licence applicants support their applications with established reserves of gas in the Western Canadian Sedimentary Basin, it is reasonable to assume that these reserves will be available to satisfy future aggregate demand whether or not the Board approves the applications. Incremental production resulting from approval of an export application will result in the production of higher cost gas so long as costs increase with increasing total production. It is the Board's view that using an applicant's own production costs would be equivalent to assuming that gas would be shut-in and not be produced over the forecast period in the absence of the approval of that application. In the Board's view, this is not a reasonable assumption. The only instances in which an export licence applicant's specific production costs would be relevant to a benefit-cost analysis would be if production of the applicant's gas were to change the Board's view of either the industry's progression up the industry supply cost curve or of the industry supply cost curve itself.

Though applicants argued that their specific direct production costs and by-product revenues should be used in the "with export" case, they used industry aggregate costs and by-product revenues in the "without export" case. The Board is of the view that such a methodology is equivalent to using two views of aggregate Canadian gas supply in the benefit-cost analysis. The Board considers it essential to maintain a consistent view of the aggregate supply of Canadian natural gas and supply costs in the analysis. Therefore, the Board concludes that the use of aggregate industry data is appropriate for the calculation of incremental by-product revenues accruing to Canada, as it is appropriate to use the industry aggregate supply cost curve for the derivation of the incremental gas production cost incurred by Canada as a whole.

In its assessment of net benefits to Canada associated with the proposed export projects, the Board has used a minimum R/P ratio of 12. This is lower than the R/P ratio of 15 which has been used previ-

ously and reflects consideration of applicants' views that a lower ratio is appropriate in the current market environment. An R/P ratio of 12 results in incremental production costs that are lower than they would be under the assumption of an R/P ratio of 15.

The Board's estimates of the operating costs of incremental transportation facilities on the TransCanada system are lower than those of the export applicants. The applicants' estimates of incremental operating costs were generally based on TransCanada's commodity charge. The Board reviewed the components of TransCanada's commodity charge and estimated that only about 25 percent of TransCanada's commodity charge represents incremental operating costs; the remainder represents recovery of capital related costs. For NOVA's incremental operating costs, the Board used an estimate of NOVA's current transportation commodity charge for all gas destined to ex-Alberta markets. The volumes used to calculate the incremental operating costs on the NOVA system include incremental fuel gas volumes on the TransCanada, Great Lakes and Union systems. Fuel and unaccounted-for losses are provided for in the calculation of the TIPC of the gas export volumes.

The Board's estimates of the incremental transportation costs downstream of the provinces of production associated with the various applications were based on TransCanada estimates. The Board finds that for all the proposed export projects, it is reasonable to expect in the control case that TransCanada's throughputs will be maintained by other shippers using the facilities if the applied-for licences were not renewed upon their termination. Therefore, in the Board's benefit-cost analyses, it reduced the capital cost of incremental facilities on the systems of NOVA, Union and TransCanada associated with each of the export applications by attributing a credit to recognize that the facilities would likely continue to be used and useful after the term of the exports.

Some of the export applicants incorporated a credit for the social opportunity cost of labour into their benefit-cost analyses. The Board is not persuaded that there are sufficient grounds to include such a credit in its analyses given the short-term nature of the construction phase of the facilities expansion and the current and projected high level of activity in the pipeline and natural gas producing industries.

The Board is also of the view that it is inappropriate to include a social premium on foreign exchange, as some applicants have done, in assessing the net benefits associated with the export applications. The foreign exchange adjustment can only be justified if one assumes that tariffs and subsidies introduce inappropriate differences between foreign and domestic prices for goods and services which would otherwise not exist in a properly functioning market. The problem with making this assumption is that it implies that existing tariffs and subsidies were imposed in order to distort a properly functioning market, rather than to correct for market imperfections. Furthermore, including a foreign exchange premium implies that tariffs, subsidies and duties will continue to exist throughout the period of the analysis. The validity of this assumption is not at all clear, given the FTA and the potential for the removal of trade restrictions with other countries pursuant to negotiations under the General Agreement on Tariffs and Trade.

For each of the export projects, the Board conducted analyses of the sensitivity of the estimates of net benefits to Canada to:

- lower and higher world oil prices;
- different discount rates;
- different load factors;
- lower and higher price escalation rates or gas prices (depending on the nature of the export sales contract); and
- the removal of the pipeline facilities cost credit.

For the purpose of the total incremental production cost calculation, sensitivities were conducted using:

- lower and higher supply costs;
- different export demand forecasts; and
- an R/P ratio of 15.

The results of the Board's benefit-cost analyses and the related sensitivity tests for each export application are shown in Chapters 2 to 9 of these Reasons.

File No. 1555-T1-160

20 November 1989

To : All Interested Parties to GH-1-89

Re: Applications of Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc., Direct Energy Marketing Limited, Indeck Gas Supply Corporation, Western Gas Marketing Limited, Western Gas Marketing Limited as agent for TransCanada PipeLines Limited, ProGas Limited and Shell Canada Limited concerning the exportation of natural gas; and an application by ICG Utilities (Ontario) Ltd concerning the exportation and re-importation of natural gas

Pursuant to Hearing Order No. GH-1-89, as amended, the Board held a public hearing from 12 April 1989 to 13 July 1989 in respect of, *inter alia,* the above-referenced applications.

In view of the lead time associated with procurement of compressors and pipe by those pipeline companies requiring additional facilities in order to transport the natural gas associated with the above applications, the Board has decided to release its decision with respect to each application with reasons to follow. Attached hereto is the Board's decision.

The GH-1-89 Reasons for Decision will be released as soon as possible.

Yours truly,

Marie Tobin
Secretary

Attach.

NEB Decision Regarding the Natural Gas Export Applications and an Import Application Examined During the GH-1-89 Hearing

IN THE MATTER OF the *National Energy Board Act*, R.S.C. 1985, c. N-7, ("the Act"), and the regulations made thereunder;

AND IN THE MATTER of an application dated 31 January 1989 by Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc. ("Amoco/Con Ed"), an application dated 12 October 1988 by Direct Energy Marketing Limited ("Direct Energy"), an application dated 14 February 1989, as amended, by Indeck Gas Supply Corporation ("Indeck"), an application dated 15 February 1989 by Western Gas Marketing Limited ("WGML") and an application dated 14 February 1989 by Western Gas Marketing Limited as agent for TransCanada PipeLines Limited ("WGML/TransCanada"), each seeking a licence to export natural gas pursuant to Part VI of the Act; filed with the Board under File No. 1555-T1-160;
AND IN THE MATTER OF an application dated 10 February 1989 by ICG Utilities (Ontario) Ltd ("ICG Ontario"), pursuant to Part VI of the Act, for a licence to export and reimport natural gas; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF an application dated 15 November 1988 by ProGas Limited ("ProGas"), pursuant to Part I of the Act, for a change, alteration or variation of gas export Licences No. GL-80 and GL-81; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF an application dated 21 November 1988 by Shell Canada Limited ("Shell"), pursuant to Part I of the Act, for a change, alteration or variation of gas export Licence No. GL-100; filed with the Board under File No. 1555-T1-160;

AND IN THE MATTER OF Hearing Order No. GH-1-89, as amended.

DECISION

Having considered the evidence adduced at the public hearing held pursuant to Hearing Order No. GH-1-89 and the arguments and submissions made by all parties, the Board has decided to:

(a) issue a new licence for the exportation of natural gas (the terms and conditions of which are itemized in Appendix 1 attached hereto) to each of Amoco/Con Ed, WGML and ProGas;

(b) issue a new licence for the exportation and subsequent re-importation of natural gas (the terms and conditions of which are itemized in Appendix 1 attached hereto) to ICG Ontario;

(c) vary Licence No. GL-81 (issued to ProGas) in order to reduce its term quantity by 10 226.3 million cubic metres;

(d) revoke Licence No. GL-80 should the Governor in Council approve ProGas' new licence referred to in paragraph (a); and

(e) deny the above-referenced applications of Direct Energy, Indeck, Shell, and WGML/ TransCanada.

The new licences referred to in paragraphs (a) and (b) and the variation of Licence No. GL-81 referred to in paragraph (c) will not take effect until Governor in Council approval thereof.

Terms and Conditions of the Licence to be issued to ProGas Limited

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2005.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 2 861 112 cubic metres in any one day;

   (b) 1 044 305 800 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 15 665 295 000 cubic metres during the term of this Licence.

3. As a tolerance, the amount that ProGas may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be issued to Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc.

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2004.

2. The quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 873 000 cubic metres in any one day;

   (b) 319 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 4 778 000 000 cubic meters during the term of this Licence.

3. Gas exported under the authority of this Licence shall be delivered to the point of export near Niagara Falls, Ontario.

Terms and Conditions of the Licence to be issued to ICG Utilities (Ontario) Ltd

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2005.

2. Subject to condition 3, the quantity of gas that may be exported and imported under the authority of this Licence shall not exceed:

   (a) 640 000 cubic metres in any one day;

   (b) 210 000 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 3 150 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that ICG Ontario may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that ICG Ontario may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. ICG Ontario may export under this Licence only that gas which is to be imported under it, and shall import all such gas so exported.

5. Gas exported under the authority of this Licence shall be delivered to the point of export near Sprague, Manitoba.

6. Gas imported under the authority of this Licence shall be delivered to the point of import near Rainy River, Ontario.

Terms and Conditions of the Licence to be issued to Western Gas Marketing Limited (for sale to Megan-Racine Associates, Inc.)

1. The term of this Licence shall commence on the date of Governor in Council approval hereof and end on 31 October 1991, unless exports commence hereunder on or before 31 October 1991, in which case the term will end on 31 October 2005.

2. Subject to condition 3, the quantity of gas that may be exported under the authority of this Licence shall not exceed:

   (a) 331 000 cubic metres in any one day;

   (b) 121 300 000 cubic metres in any consecutive twelve-month period ending on 31 October; or

   (c) 1 820 000 000 cubic metres during the term of this Licence.

3. (a) As a tolerance, the amount that WGML may export in any 24-hour period under the authority of this Licence may exceed the daily limitation imposed in condition 2 by ten percent.

   (b) As a tolerance, the amount that WGML may export in any consecutive twelve-month period under the authority of this Licence may exceed the annual limitation imposed in condition 2 by two percent.

4. Gas exported under the authority of this Licence shall be delivered to the point of export near Cornwall, Ontario.